Development of next generation energy system simulation tools for district energy

Andersen, Anders N.

DOI (link to publication from Publisher):
10.5278/vbn.307981610

Publication date:
2019

Document Version
Publisher's PDF, also known as Version of record

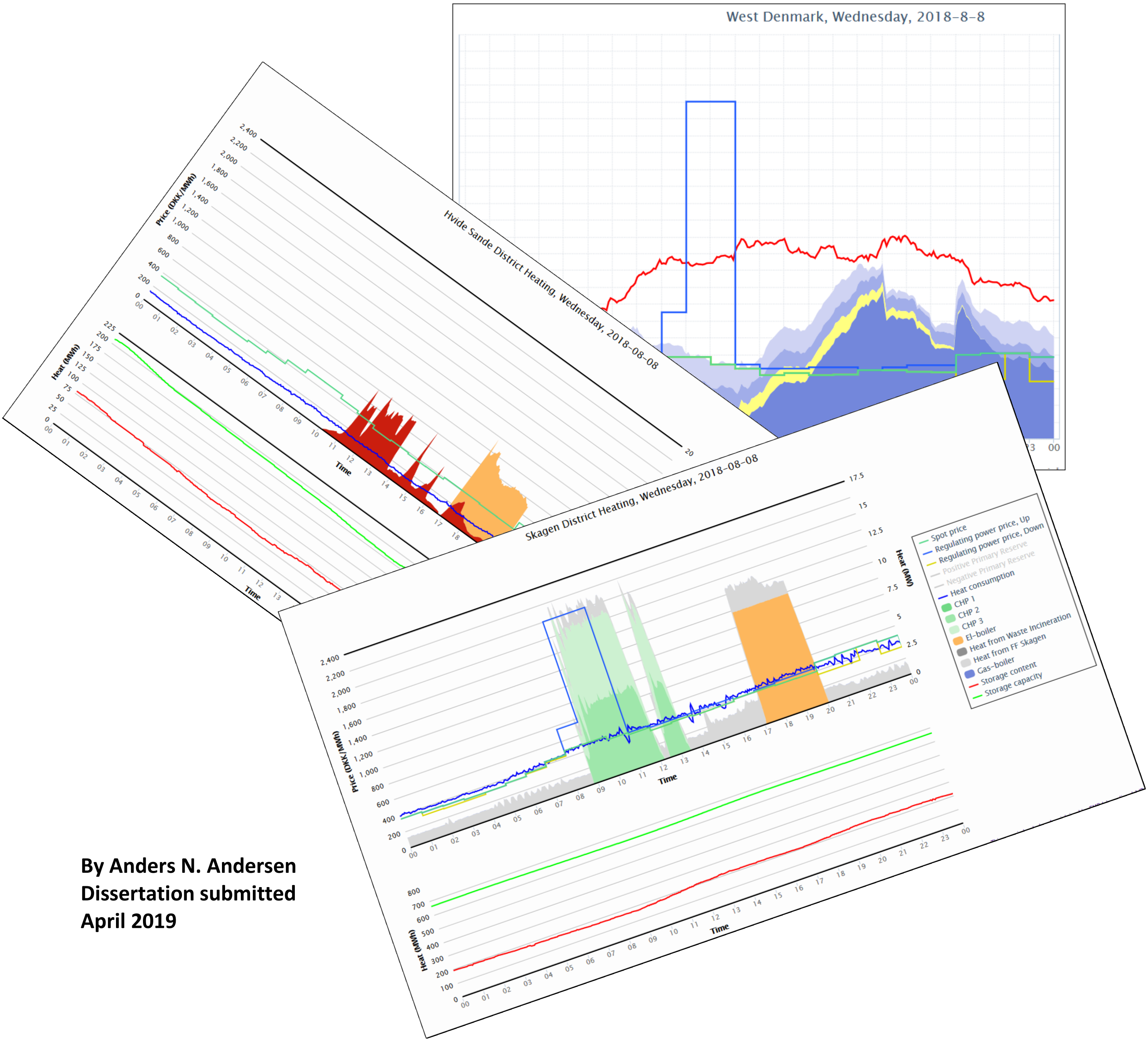
DEVELOPMENT OF NEXT GENERATION ENERGY SYSTEM SIMULATION TOOLS FOR DISTRICT ENERGY

BY
ANDERS N. ANDERSEN

DISSERTATION SUBMITTED 2019

AALBORG UNIVERSITY
DENMARK

Development of next generation energy system simulation tools for district energy



By Anders N. Andersen
Dissertation submitted
April 2019

Dissertation submitted: 08-04-2019

PhD supervisor: Professor Poul Alberg Østergaard,
Aalborg University

PhD committee: Associate Professor Karl Sperling (chairman)
Aalborg University

Associate Professor Gorm Bruun Andresen
Aarhus University

Dr.-Ing. Bernhard Wille-Haussmann
Fraunhofer ISE

PhD Series: Technical Faculty of IT and Design, Aalborg University

Institut: Department of Planning

ISSN (online): 2446-1628
ISBN (online): 978-87-7210-423-2

Published by:
Aalborg University Press
Langagervej 2
DK – 9220 Aalborg Ø
Phone: +45 99407140
aauf@forlag.aau.dk
forlag.aau.dk

Printed in Denmark by Rosendahls, 2018

English summary

Energy systems in many countries are undergoing a transition from largely being based on few condensing mode central power plants, to among other being based on more geographically distributed productions at District Energy (DE) plants, where cogenerated electricity, heating and cooling creates efficient solutions for reducing greenhouse gas emissions and primary energy demand.
Furthermore, flexible DE plants have an important role in the transition to a renewable energy system. They may become major actors in integrating wind and solar power, when equipped with amongst others combined heat and power units and heat pumps producing both heating and cooling, and when equipped with large energy stores.
This integration of the DE plants with the rest of the energy system will often be based on biddings in electricity and fuel markets, being affected by availability of fluctuating energy sources, as well as being affected by complex subsidy schemes and energy taxes. This calls for new generalized tools which are able to analyse very different alternatives for DE plants providing heating and cooling.

The research made in this PhD study concerns the development of this next generation energy system simulation tools for designing and operating DE plants.

The starting point for this research has been if it possible to develop a generalized tool, which is able to analyse very different alternatives for DE plants providing heating and cooling, thus making it manageable by managers of DE plants and their consultants to compare radically different alternatives in one tool.

It is assumed that it will promote better alternatives for DE plants to be chosen, when carefully choosing sufficient detailing of each component of the energy system and avoiding needless detailing, which could compromise the ambition of comparing very different alternatives in the same tool.

The research has been delimited to those tools needed for the following tasks in DE plants:

- Investment analysis of alternatives for complex future DE plants operating in complex energy markets subject to complex support schemes and energy taxes.
- Daily or short-term planning of operation, also when this operation is determined from biddings in the electricity and fuel markets and affected by availability of fluctuating energy sources, large energy stores and restricted capacities in the heating, cooling and electrical grids.

Thus, the focus in this PhD study is on heating, cooling and electricity demands in more buildings supplied from DE plants, typically equipped with energy stores, such as heating, cooling, fuel or electricity stores. The operation is often market-based and optimized across different energy types, of which each may be subject to restricted grid capacities between the DE plants and the buildings. The focus in the development is on optimizing the operation of the production units and the energy stores at the plants. However, optimization across plants, grids and buildings are dealt with in some detail.

The main research question is formulated as:
Is it possible to develop a tool which is able to analyse sufficiently detailed very different alternatives for DE plants providing heating and cooling?

For such a tool to be appropriate for practitioners, it has to offer an acceptable time setting up models, an acceptable calculation time and it should use a calculation method understandable by the managers of the DE plants.

To make this research question operational as well as to delimit it, three sub questions have been formulated:

Sub question 1: *How can the optimization of market-based daily operation of DE plants with large TES be solved?*

Sub question 2: *How can a coordinated investment in production and storage capacity at DE plants be analysed?*

Sub question 3: *How can the effect of support schemes promoting necessary flexibility at DE plants be analysed?*

The thesis is divided into the following seven sections:

For establishing the research's novelty and general applicability, Section 1 presents a literature review, which is split into six subsections, each dealing with aspects of the sub questions. These aspects are the societal benefits of DE, the needed flexibility of DE plants, the changing roles of combined heat and power at DE plants when developing renewable energy, the needed optimization of daily operation of DE plants with large TES, the needed support schemes promoting necessary flexibility at DE plants and the estimated yearly investment in production capacity at DE plants.
Based on this review, Section 1 states the scope and research questions for this thesis.

Section 2 describes the methodology used in this thesis and it is stressed how the methods developed in this thesis have benefitted from the methods met in several of the completed PhD courses.

Section 3 deals with Sub question 1 by comparing different unit commitment (UC) methods at DE plants. A complex generic DE plant case has been designed. Two significantly different UC methods are presented and applied to the case. The application shows that these two UC methods provide same optimizations of the market-based daily operations of such complex generic DE plants with large TES, hence offering more solutions how the optimization of market-based daily operation of DE plants with large TES can be solved in a sufficient detail and sufficiently fast.

Section 4 deals with Sub question 2 by presenting a method for analysing coordinated investments in production and storage capacity. It is demonstrated in this section that the presented method returns reliable results, when dealing with the complex generic DE plant considered and when being based on one of the two UC methods described in Section 3.

Section 5 deals with Sub question 3 by presenting a method for comparing the effect of support schemes at DE plants. The methods are used to compare two support schemes, one of a Feed-in premium type and one of a Feed-in tariff type. The effect of these two support schemes are demonstrated on the complex generic DE plant, when using the method for analysing coordinated investments in production and storage capacity presented in Section 4. It is shown that the societal cost for providing a certain production capacity, measured as the support in the planning period, is around three time larger when using the presented Feed-in premium type as when using the Feed-in tariff type.

Section 6 presents DE plants, that differ significantly from the generic DE plants studied in this PhD study, therefore needs further to be researched in the future.

Finally, Section 7 concludes on the work done in this PhD study as an important step towards the development of next generation energy system simulation tools for district energy being able to analyse very different alternatives for DE plants providing heating and cooling.

Dansk Resumé

Forskningen i dette PhD studie vedrører udviklingen af næste generation af energisystemanalyse-værktøjer til design og daglig driftning af fjernvarmeværker.

Udgangspunktet for forskningen har været, om det er muligt at udvikle et generaliseret værktøj, der gør det overkommeligt for fjernvarmeværkerne og deres rådgivere at analysere og sammenligne meget forskellige alternativer til fjernvarmeværkerne. Det er antaget, at ved omhyggeligt at vælge en tilstrækkelig detaljeringsgrad af hver komponent i energisystemet og undgå unødvendige detaljer, vil man i det samme værktøj kunne sammenligne meget forskellige alternativer, dermed fremme at bedre alternativer til fjernvarmeværkerne vil blive valgt til at løse de opgaver værkerne har ved omstillingen af det samlede energisystem til vedvarende energi.

Forskningen er afgrænset til at omfatte et værktøj, der er nødvendig for følgende opgaver på værkerne:

- Investeringsanalyser af alternativer for komplekse fremtidige fjernvarmeværker, der opererer på komplekse energimarkeder underlagt komplekse støtteordninger og energiafgifter.
- Daglig planlægning af driften af disse værker, når denne drift bestemmes af bud på el- og brændstofmarkederne og påvirkes af fluktuerende produktion på f.eks. store solvarmeanlæg, samt når der skal tages højde for store energilagre og begrænsede kapaciteter i varme- og kølenet.

Formålet med forskningen er som nævnt at afdække, om det er muligt at udvikle et fælles generaliseret værktøj, der er i stand til at gennemføre ovenstående opgaver, men forskningen er afgrænset til at afdække følgende delspørgsmål:

- Hvordan kan man beregne en markedsoptimeret drift af et fleksibelt fjernvarmeværk, udstyret med stor produktions- og lagerkapacitet?
- Hvordan kan man analysere samtidig investering i produktions- og lagerkapacitet på fjernvarmeværkerne?
- Hvordan kan virkningerne af forskellige støtteordninger beregnes?

I denne afhandling er der også arbejdet med bl.a. de samfundsmæssige fordele ved fjernvarme, den nødvendige fleksibilitet af værkerne og den ændrede rolle af kraftvarme når der udbygges med vindkraft og solceller.

I afhandlingen er beskrevet og sammenlignet to væsentligt forskellige metoder til beregning af optimeret daglig drift. Der er beskrevet en metode til at analysere samtidig investering i produktions- og lagerkapacitet, samt beskrevet en metode til at sammenligne virkningen af væsentligt forskellige støtteordninger. Der er bl.a. vist et eksempel på at for at fremme den samme produktionskapacitet på værkerne skal den samlede støtte over en planperiode være rundt regnet tre gange større hvis man anvender et fast elproduktionstilskud tillagt spotprisen end hvis man anvender en treledstarif.

Afslutningsvist er diskuteret mere specielle fjernvarmeværker og diskuteret deltagelse på tværs af flere elmarkeder. Denne diskussion ender ud i en anbefaling om yderligere forskning i næste generation af energisystemanalyse værktøjer til design og daglig driftning af fjernvarmeværker, hvor også disse mere specielle tilfælde analyseres.

Acknowledgements

The work presented in this dissertation is part of the research activities of the Strategic Research Centre for 4th Generation District Heating (4DH), which has received funding from Innovation Fund Denmark, grant number 0603-00498B.

The work started a little more than three years ago when my supervisor, Professor Poul Alberg Østergaard, asked me why I did not commence a PhD study, researching my yearlong striving concerning the development of one generalized tool which - in the best company perspective of the societal Choice Awareness theory - should be able to analyse very different alternatives for District Energy plants providing heating and cooling. My answer was clear-cut: if he was willing to supervise me, I would be very happy to do so. Without his support and endless fighting for always making me think 360° at each problem and his ceaseless commitment to improving my Google English, this work would not have been possible.

Furthermore, through my stay these three years at the Energy Systems Department at the company EMD International A/S, I would like to thank Leif H. Tambjerg and Christian Frandsen for the daily discussions about sufficient detailing of each component of the energy system and for avoiding needless detailing, which could compromise the ambition of comparing very different alternatives in the same tool.

I would like to thank the lecturers of the PhD courses conducted as a part of my PhD study. Amongst others I would like to thank Professor Andres Ramos from Comillas Pontifical University in Spain for introducing me to using solvers for calculating optimal daily operation of energy systems (unit commitment), which has inspired me to use these in my research. Professor Moises Graells from Technical University of Catalonia and Associate Professor Eleonora Riva Sanseverino from University of Palermo introduced me to methods on how to formulate different energy system optimization problems in a broader perspective, which raised my interest to compare analytic and solver-based methods. Thanks to Associate Professor Thomas Arildsen from Aalborg University´s PhD Consult for assisting me in setting up the Mixed Integer Linear Problem in Gurobi Optimizer interfaced by Python. Thanks to Associate Professor Derso Sera and Associate Professor Tamas Kerekes from Aalborg University, who made me fully appreciate that Photo Voltaic is one thing when looked upon as a single component, but when being part of an energy system, e.g. when located within a wind farm that creates shadows from the wind turbine blades, is quite another thing. Furthermore, I would like to thank Dr. Daniel Stroe and Dr. Erik Schaltz, Aalborg University, who made me aware of the complexity of modelling electrical battery ageing, performance degradation and lifetime estimation of batteries.

Being responsible together with Poul Alberg Østergaard for the Energy System Analysis course offered by The Sustainable Energy Planning Research Group, Department of Planning, Aalborg University, I would like to thank the students on this course through the years for many fruitful discussions about my vision of having only one tool capable of analysing very different alternatives for District Energy plants. Their abundance of examples was certainly a challenging inspiration to this vision.

I would like to thank the colleagues of The Sustainable Energy Planning Research Group for many fruitful discussions. Specifically, I would like to thank the colleagues participating in the study circle in energy storage being supervised by Poul Alberg Østergaard; David Drysdale, Kenneth Hansen and Louise Krog Jensen, who made me develop a more generalised view on energy stores.

Finally, I would like to thank the Energy Group in the community Stærhøj, where I am living and where the 16 houses are connected with a neighbour district heating scheme, for fruitful bottom up discussion about sustainable very different heating solutions for this small-scale district energy system.

And finally, and not least, of course, thanks to my wife, Kamma Raunkjær, for accepting and supporting me during the many hours in the last three years I have spent developing this work. Without your support this thesis would not have been possible.

Contents

Annexes:

Papers appended:

List of appended papers

This dissertation is based on four journal papers and an article in an international magazine, which are included as appendices.

I. Andersen, Anders N.; Østergaard, Poul A. *A method for assessing support schemes promoting flexibility at district energy plants*. Accepted and published in Applied Energy September 2018, doi.org/10.1016/j.apenergy.2018.05.053

II. Andersen, Anders N.; Østergaard, Poul A. *Analytic versus solver-based calculated daily operations of district energy plants*. Accepted and published in Energy May 2019, https://doi.org/10.1016/j.energy.2019.03.096

III. Andersen, Anders N.; Østergaard, Poul A. *Support schemes for the radically changing role of District Energy CHPs through the transition to a renewable energy*. Under review for second review round in Energy

IV. Østergaard, Poul A.; Andersen, Anders N. *Booster heat pumps and central heat pumps in district heating*. Accepted and published in Applied Energy December 2016, doi.org/10.1016/j.apenergy.2016.02.144

V. Andersen, Anders N.; Østergaard, Poul A. *New roles of CHPs in the transition to a Renewable Energy System.* Accepted and published in HOT/COOL - International Magazine on District Heating and Cooling, Vol. 1, 2017

Other relevant publications, which are not included in the appendices:

Østergaard, Poul A.; Andersen, Anders N. *Economic feasibility of booster heat pumps in heat pump-based district heating systems*. Energy July 2018, doi.org/10.1016/j.energy.2018.05.076

List of abbreviations

ACER	Agency for the Cooperation of Energy Regulators
CHP	Combined Heat and Power
DE	District Energy
DH	District Heating
ECU	Energy Conversion Unit
GAMS	General Algebraic Modelling System
HP	Heat Pump
MINLP	Mixed integer nonlinear programming
MPPT	Maximum power point tracker
NHPC	Net Heat Production Cost
NPC	Net Production Cost
NPV	Net Present Value
PL	Priority List
RES	Renewable Energy Sources
SBL	Start Block List
TES	Thermal Energy storage
UC	Unit Commitment
VBA	Visual Basic for Application

1. Introduction

Energy systems in many countries are undergoing a transition from largely being based on few condensing mode central power plants and on individual or communal boilers producing only heat, towards among other more geographically distributed productions at DE plants, where cogeneration of electricity, heating and cooling creates efficient solutions for reducing greenhouse gas emissions and primary energy demand.
Furthermore, flexible DE plants have an important role in the transition to a renewable energy system. They may become major actors in integrating wind and solar power, when equipped with CHPs, heat consuming absorption chillers and heat pumps producing both heating and cooling. This integration of the DE plants with the rest of the energy system will often be based on biddings in the electricity and fuel markets and affected by availability of fluctuating energy sources, large energy stores and restricted capacities in the heating, cooling and electrical grids. Adding to this complex subsidy schemes often are needed. This calls for new generalized tools which are able to analyse very different alternatives for DE plants providing heating and cooling.

For establishing the research's novelty and scope this section presents a literature review focusing on the societal benefits of DE, the needed flexibility of DE plants, the changing roles of CHP at DE plants when developing renewable energy, the needed optimization of daily operation of DE plants with large energy stores, the needed support schemes promoting necessary flexibility at DE plants and the estimated yearly investment in production capacity at DE plants.

The novelty of the research in this PhD has also been dealt with in detail in the five papers that this synthesis is based upon. Parts of the text in this chapter is copied verbatim from these five papers, however, being synthesised and made coherent.

Based on this review, the specific objective of the thesis is established at the end of the section.

1.1 Societal benefits of District Energy

The development of modern (i.e., energy-efficient and climate-resilient) and affordable DE systems in cities is one of the least-cost and most-efficient solutions for reducing greenhouse gas emissions and primary energy demand [1]. A transition to such systems, combined with energy efficiency measures, could contribute as much as 58% of the carbon dioxide (CO_2) emission reductions required in the energy sector by 2050 to keep global temperature rise within 2–3 degrees Celsius [1].

Another important reason for this development of DE systems, is that an increasing number of people live in urban areas, with 55 % of the world's population residing in urban areas in 2018. In 1950, 30 % of the world's population was urban, and by 2050, 68 % of the world's population is projected to be urban. Today 74% of the European population live in urban areas [2]. Especially in cities with high heat densities it becomes feasible to establish DE plants providing heating and cooling to more buildings [3]. The reason is amongst others that it promotes the exploitation of waste heat from power plants and industry [4]; that a significant economy of scale-effect in solar collectors makes communal systems much cheaper to build compared to solar collectors at each building [5]; that heat pumps (HP) get access to a broader range of heat sources, e.g. heat from sewage systems [6] and that for many cities it will be possible to exploit geothermal energy [7]. Similarly, more cooling sources become available, e.g. free cooling from lakes, rivers or seas [8].

Furthermore, flexible DE plants providing heating and cooling to cities have an important role in the transition to a renewable energy system. They may become major actors in integrating wind and solar power, when equipped with CHPs, heat consuming absorption chillers, HPs producing both heating and cooling and large Thermal Energy Storage (TES).

The EU has set a long-term goal of reducing greenhouse gas emissions by 80-95% by 2050, when compared to 1990 levels. The EU Energy Roadmap 2050 explores the transition of the energy system in ways that would be compatible with this greenhouse gas reduction target [9]. The conclusions of Energy Roadmap 2050 are that decarbonising the energy system is technically and economically feasible in the long run, that all scenarios that achieve the emissions reduction target are cheaper than the continuation of current policies and that increasing the share of renewable energy and using energy more efficiently is crucial, irrespective of the particular energy mix chosen.

In the European Union (EU) heating and cooling represent around half of the final energy consumption. It is a bigger end-use sector than transport and electricity, and today only 15% is covered by Renewable Energy Sources (RES) [10]. Energy Roadmap 2050 has not detailed how to cover heating and cooling demands, but only proposed electrification of the heating sector (primarily using HPs) and implementation of electricity and heat savings. However, this detailing has been made in the research project Heat Roadmap Europe [11] which concludes that a 30-40% reduction of the existing heat demand in Europe is socio-economic feasible, and approximately 50% of the remainder should be covered by DE. The results of this research project indicate that with this large-scale implementation of DE, compared to not implementing DE, the EU energy system will be able to achieve the same reductions in primary energy supply and carbon dioxide emissions at a lower cost, with heating and cooling costs reduced by approximately 15%, which is a €100 billion per year [10], down from €675 to €575 billion per year.

More factors contribute to societal benefits of DE compared to individual supply in each building of heating and cooling. Improved insulation standards reduces heat to be delivered to the buildings, thus influencing the expansion of DH grids. Möller & Nielsen [12] established a so-called *heat atlas* to investigate heat demands in Denmark to be able to assess the potential for DH expansion. Sperling & Möller [13] found that *"end-use energy savings and district heating expansion combined in the existing energy system improve the overall fuel efficiency of the system".* Furthermore, Østergaard [14] points at the systems effects of realising heat savings in DH areas as it impacts the operation of CHP plants providing ancillary services – and reduces their ability to integrate RES-based electricity production. Likewise, Thellufsen & Lund [15] stress the need for assessing the benefits of savings on an energy systems level.

Lund et al. [16] conclude that *"A suitable least-cost heating strategy seems to be to invest in an approximately 50% decrease in net heat demands in new buildings and buildings that are being renovated anyway, while the implementation of heat savings in buildings that are not being renovated hardly pays"*. This calls for tools to be able to divide heat demands connected to DE plants in different types depending on the age of buildings in the different areas. Mosgaard & Maneschi [17], however, stress the complexity of energy renovations and the circumstance that even economically favourable energy savings are not always carried out. All in all, this calls for integrated studies of optimal heating solutions – individual or DH combined with savings – in future high-RES energy systems, as performed in e.g. [11].

An important factor when estimating the societal benefits of DE concerns CHP. Fossil-based CHP has no long-term future in an energy system switching to RES, thus DH will need to rely on other heat sources. Low electricity prices and high natural gas prices lower the profitability of CHP units to the extent that some swap to heat only boilers. This may push the balance between DH and individual heating solutions including individual HPs. Also, progressively more energy-efficient houses and a steadily improving HP performance for individual dwellings are straining the societal advantage of DE plants as grid losses are growing in relative terms due to decreasing heating demands of buildings.

1.2 Needed flexibility and efficiency of DE plants

The determination of needed flexibility and efficiency of DE plants takes its starting point in the complexity that may be envisaged at DE plants.

The DE plants may e.g. include combinations of the following Energy Conversion Units (ECUs):

- CHP being operated in both extraction and condensing mode
- Heat pumps, even producing both heat and cooling
- Tri-generation plants with absorption cooling units, where electricity, heat and cooling are coproduced
- Biogas plants, where the fuels are restricted
- Biomass plants, where the start-up time of CHP-production is significant
- Wind farm and Photo Voltaic connected in a private wire to the DE plant
- Solar thermal
- Fuel factories, where waste heat from the plant may cover heat demand
- Heat-only boilers

The DE plant may include a large range of energy types, e.g.:

- Electricity
- Steam
- Process heat
- Hot water
- Cold water
- Natural gas
- Wood chips
- Gasified biomass
- Hydrogen
- Biogas
- Coal

Furthermore, dump of energy for each energy type may be included e.g.:

- Cooling towers
- Flaring of biogas

The ECUs at the DE plant may be situated at more sites. Similarly, the heating and cooling demands supplied by the DE plant may be situated at more sites. The transmission between sites of the different energy types may be restricted, and there may be stores of each energy type in each site.

Research in needed flexibility of DE plants is extensive. Mathiesen & Lund [18] conclude that *"Large-scale heat pumps prove to be especially promising as they efficiently reduce the production of excess electricity".* Connolly & Mathiesen [19] propose that after the introduction of DH the introduction of small and large-scale heat pumps is the second stage in a transition to Renewable Energy (RE) supply. Østergaard [20] finds that compression HPs can play a role in the integration of wind power as they limit boiler-based DH production as well as electricity excess – though at the same time also tend to increase condensing-mode power generation. The same author investigates different optimisation criteria for assessing the optimal introduction of HPs in DH, finding that *"different optimisation criteria render different optimal designs"* [21]. The above-mentioned research have mainly focused on the macro-scale, and often based on simplified analyses using fixed COP values and without detailed analyses of temporal variations in losses or demand-specific losses in the DH system, which is expected to be important features to be handled in a future generation of energy system analysis tools.

In general, in the future, a shift towards further electrification of the energy systems may be foreseen [22], often being based on HPs. This stress the importance of temperature levels in the energy system. A main driver for forward temperature in DH is the requirements for domestic hot water (DHW) production. This raises the question if electrification is optimally made with central solutions at DE plants, with individual solutions at each building or with a combination of central and individual solutions. Østergaard and Andersen [23] have investigated two alternatives for DHW supply: a) DH based on central HPs combined with a heat exchanger, and b) a combination of DH based on central HPs and small booster HPs using DH water as low-temperature source for DHW production. The results indicate that applying booster HPs enables the DH system to operate at substantially lower temperature levels, improving the COP of the central HP while simultaneously lowering DH grid losses significantly. Thus, DH performance is increased significantly.

Specifically on booster HPs providing DHW, Köfinger et al. [24] found that *"Booster for DHW preparation are possible solutions if the grid temperature is too low or DHW needs to be stored e.g. in larger buildings like Hotels"* and Zvingilaite et al. [25] analysed low-temperature DH systems in combination with small booster HPs with the purpose of supplying DHW in DH systems with forward DH temperatures below the required DHW temperature. In one typology, DH water was split in two streams; one passing the condenser and one passing the evaporator of a booster HP, thus creating 53°C hot water from 40°C DH water; sufficient to produce DHW at 45°C with a reasonable heat exchanger temperature difference. Similarly, Ommen et al. [26] present analyses of booster HPs in the actual DH system of Copenhagen, Denmark, with operation being optimised against hourly Day-ahead market prices. The work however is primarily based on CHP and how lowering DH forward temperatures benefit the operation of CHP units using temperature performance curves. The authors *"recommend the use of 65-70°C as the optimal forward temperature for DH networks, since lower temperatures require high investment, among others DH booster HP units in each dwelling".* Likewise, Elmegaard et al. [27] investigate low-temperature DH systems combined with booster units. These analyses are also based on the combination of CHP and DH and are furthermore based on yearly average consumption rates and not a high temporal resolution. The authors find that *"Conventional systems with higher temperatures in the network have a better utilization than low temperature solutions, as the decrease in heat loss does not compensate the electricity demand to cover the energy consumption."*

Lund et al. [28] have demonstrated that, in general, low temperature is preferable due to lower DH grid losses, thus noticing that DH development has seen a decline in temperatures over the past century. In addition, they state that when turning to HPs, lowering DH forward temperatures improves the COP of HPs producing DH, thus the DH development towards lower temperature levels facilitates a switch to HPs.

1.3 The changing roles of CHP at DE plants when developing renewable energy

Next generation energy system tools for simulating DE plants must as a minimum be able to simulate the changing roles of CHP at DE plants when developing renewable energy. This is in this section exemplified by a description of the changing roles that have been observed at distributed CHP plants in Denmark. The Danish Energy Agency has illustrated how the development of CHP changed the Danish energy system – see Figure 1. From a few power plants in the beginning of the 1980s to thousands of power producing units today where, besides the central power plants, 285 distributed DE plants, 380 industrial and private plants are equipped with CHP. Added to this more than 5000 on-shore wind turbines and more than 500 off-shore wind turbines are in operation [29].

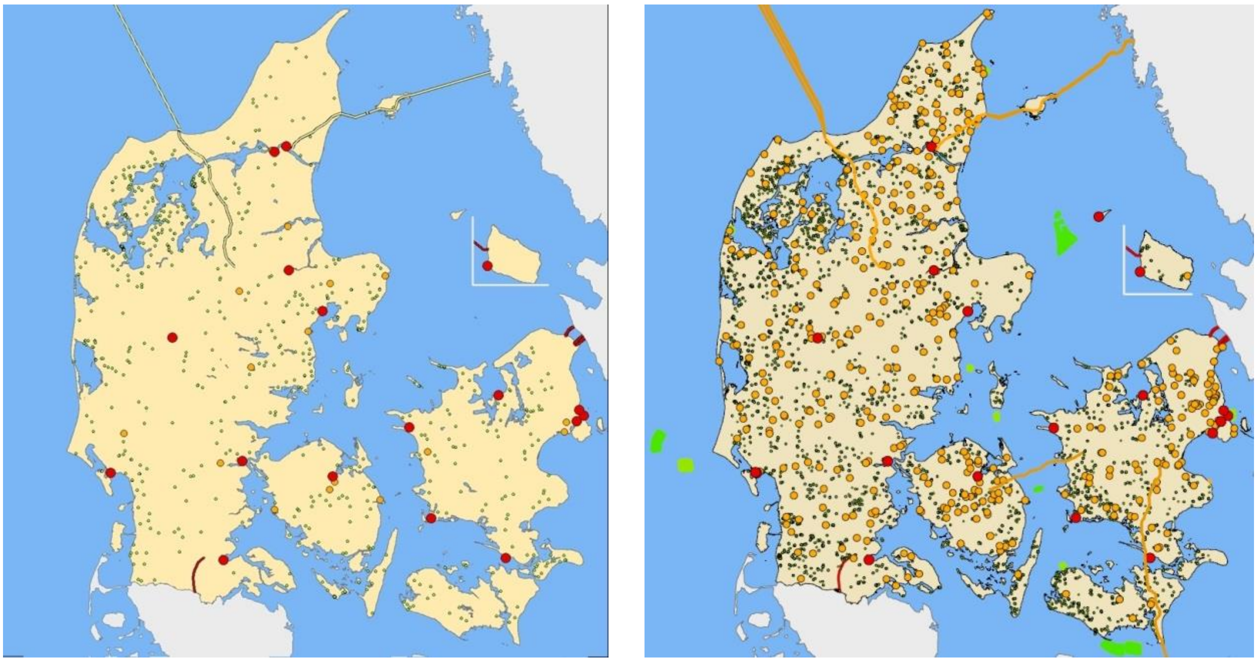


Figure 1: The electrical infrastructure in Denmark in 1985 (left) and 2013 (right). Red circles indicate central power plants, yellow circles DE CHPs and secondary producers above 500 kW. The green dots show wind turbines and green off-shore areas show off-shore wind farms [30]**.**

1.3.1 Phase 1: CHP displaces fossil fuelled power plants

In the first phase with an energy system largely based on condensing mode power generation and individual or communal boiler production of heat, the CHPs' task in Denmark was to displace the fossil fuelled condensing mode power plants as well as to displace production on individual and communal boilers – restricted of course by the heat demand that was served by CHP. With condensing mode power generation having efficiencies around 40% and CHP plants having a total efficiency of 90%, the CHP and DE combination offers clear advantages from an energy efficiency point of view, as each 1 MWh_e displaced on a condensing mode power plant saves 1 MWh_{fuel}. This efficiency potential is also in focus
on e.g. a European level [11,31].

The development of the electrical capacity in Denmark is shown in Figure 2. The development of Distributed CHP started in 1985 and was substantially finished around 2000, and the support for this development was based on a production time-dependent triple tariff providing incentives to produce during peak load hours. The paid price for electricity was high in the morning and late afternoon, low in night hours and weekend and in between in the other hours.

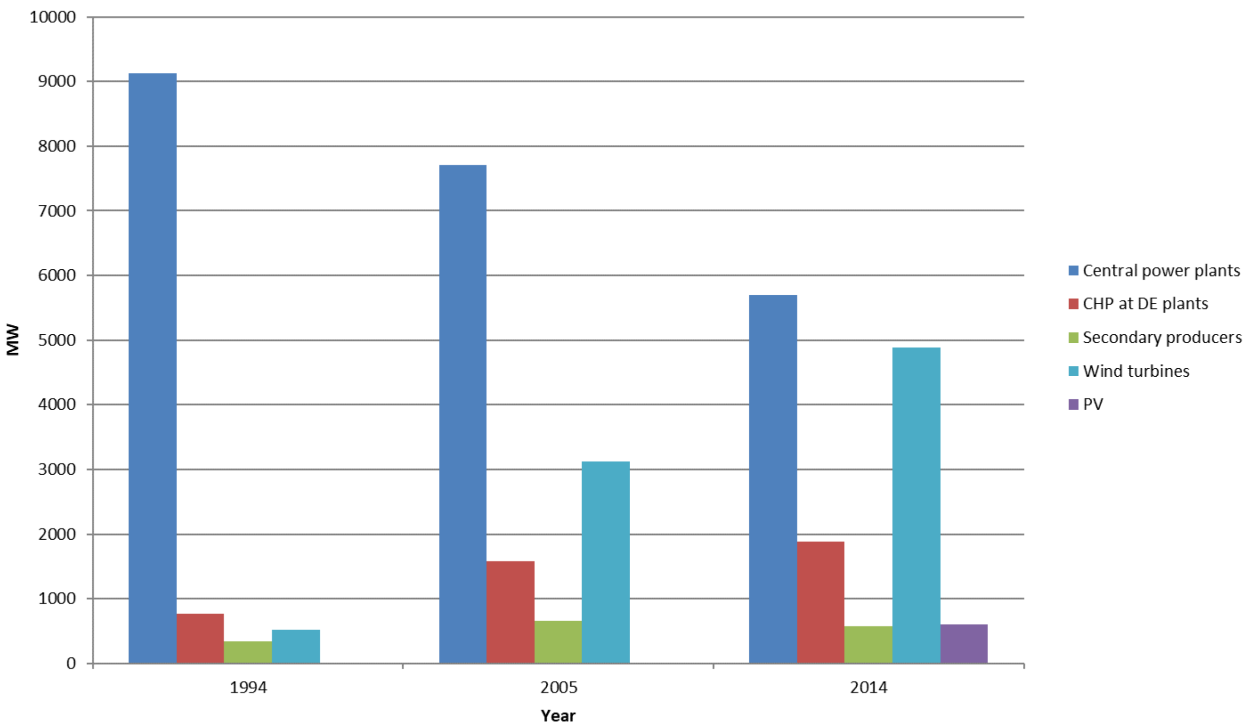


Figure 2: Electricity production capacity in Denmark in the last 20 years, according to data from [32]. *The central power plants are situated at 16 sites. The DE CHP is situated at DH companies. The secondary producers are industrial producers and waste incineration plants.*

The steepest increase in distributed CHP-capacity happened in the years from 1992 to 1997. Wind power experienced an even higher increase as also shown in Figure 2. During the same period of time, the installed capacity on central power plants decreased by more than one third in spite of a gradual increase in domestic electricity demand from 1990 to 2014 of 8.6 percent [32]. Thus, Danish power production has been effectively shifted to a more geographically distributed production. This required a whole new way of dispatching electricity production, from mainly a centrally dispatched electricity production in the 1980s to a distributed electricity production more based on many balancing responsible parties today.

1.3.2 Phase 2: CHP participates in the integration of fluctuating RES

The development of wind power in Denmark took place in parallel to the development of distributed CHP-plants, and after year 2000 it began to happen that wind turbines had to be stopped - amplified by the situation that CHPs at distributed DE plants continued to produce. The Danish Parliament thus decided that the triple tariff paid for CHP production at distributed DE plants, was to be phased out from 2005 to 2015 [33]. This meant that from 2005 many of the CHPs were market-operated and most of these were traded in the Scandinavian day-ahead market.

In Figure 3 is shown a simulation made in the energy system analysis tool energyPRO [34] of a market based operation of a DE CHP-plant in two weeks in the autumn of 2015. The simulation shows that the two CHP units are only operated in hours with sufficiently high Day-ahead prices. In this way the CHPs participate in the integration of wind and PV production, as it will seldom happen that wind turbines have to be curtailed in hours with high spot prices, since the bidding prices in day-ahead market of the wind turbines are close to zero.

The size of the thermal store shown in Figure 3 is so large that it is possible for the two CHP units to operate in all hours with sufficiently high Day-ahead prices from Monday 28th of September to Friday 2nd of October.

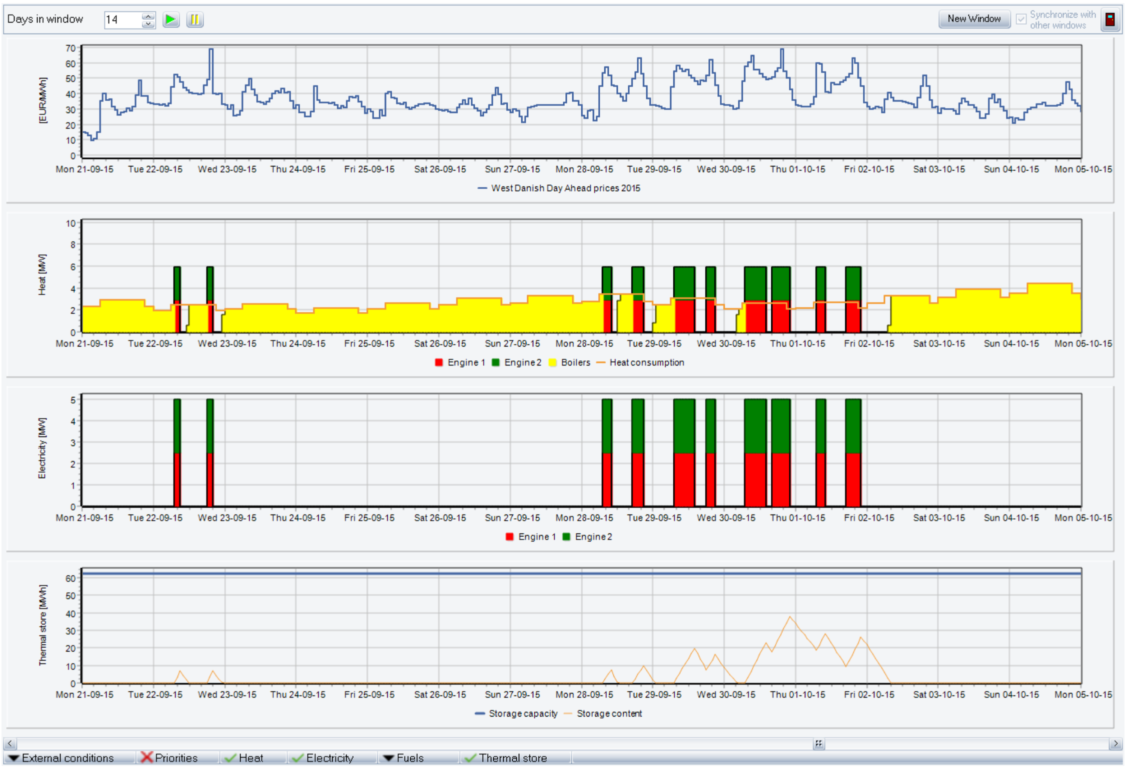


Figure 3: Simulated operation against the Scandinavian day-ahead market in two weeks in the autumn of 2015 of a CHP-plant equipped with large electrical capacity and large thermal store. The simulation is made in the energy systems analysis tool energyPRO [34].

The fact that they stopped receiving the triple tariff and instead started receiving market prices created a financial problem for distributed DE plants. In most months market prices were lower than the triple tariff. The distributed DE plants had invested in CHPs with large electrical capacity and large TES, with the expectation that the triple tariff would be paid. To secure the investments that distributed DE plants had already made, the Danish Parliament made an electrical capacity market for each single distributed DE plant that already had invested in CHP units [33]. This capacity market is made so that in each month each distributed DE plant receives a production-independent payment equal to the difference between what this plant could have earned on the triple tariff and what it can earn in the Scandinavian day-ahead market.

Even if this capacity payment is different for each distributed DE plant, it was made easier to administer by calculating for a selected year before 2005, what this DE plant had earned in the triple tariff and what it would have earned that year, if it had instead been paid the hourly prices in the Scandinavian day-ahead market. This "loss" is converted to a factor times a piecewise linear function. The factor is unique for each distributed DE plant but the index function (see Figure 4) is identical for all distributed DE plants and dependent on the monthly average price in the day-ahead market (spot price).

As Figure 4 shows, in month with a monthly average price in the Day-ahead market above 56 EUR/MWh_e the DE plant receives no capacity payment, which is to say that with high day-ahead prices in a month, this DE plant would not have earned more on the triple tariff. At the other end of the register, at a monthly average spot market price less than 18 EUR/MWh_e, capacity payments are maximised.

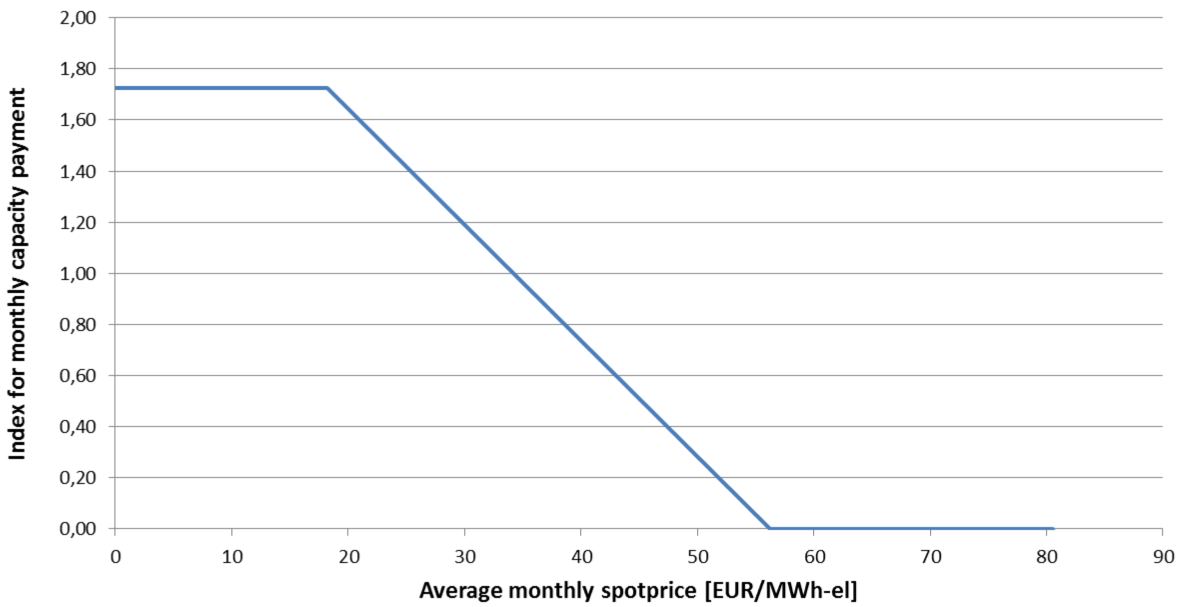


Figure 4: Index function to be used for calculating monthly capacity payment to DE plants.

1.3.3 Phase 3: CHP primarily delivers needed electrical capacity in few hours

In Figure 5 is **Error! Reference source not found.**shown the yearly electricity productions at distributed DE plants in Denmark. In 2014 CHPs at distributed DE plants produced only 6% of the Danish consumption [32], down to the same amount as the secondary producers, even if the secondary producers were only equipped with one third of the electrical capacity of the CHPs at distributed DE plants, as seen in Figure 2. The central power plants produced 39%, half of it being in condensing mode and half of it being in extraction mode with heat delivered to the big cities. Wind power produced 39% of the Danish consumption and 8% was imported. It is thus to be noticed that the decrease in CHP at distributed DE plants happens even if there are still central power plants producing in condensing mode, which seems in contradiction to Phase 1 operation, where the CHPs' task is to displace fossil fuelled condensing mode power plants by producing as much electricity as the heat demand allows.

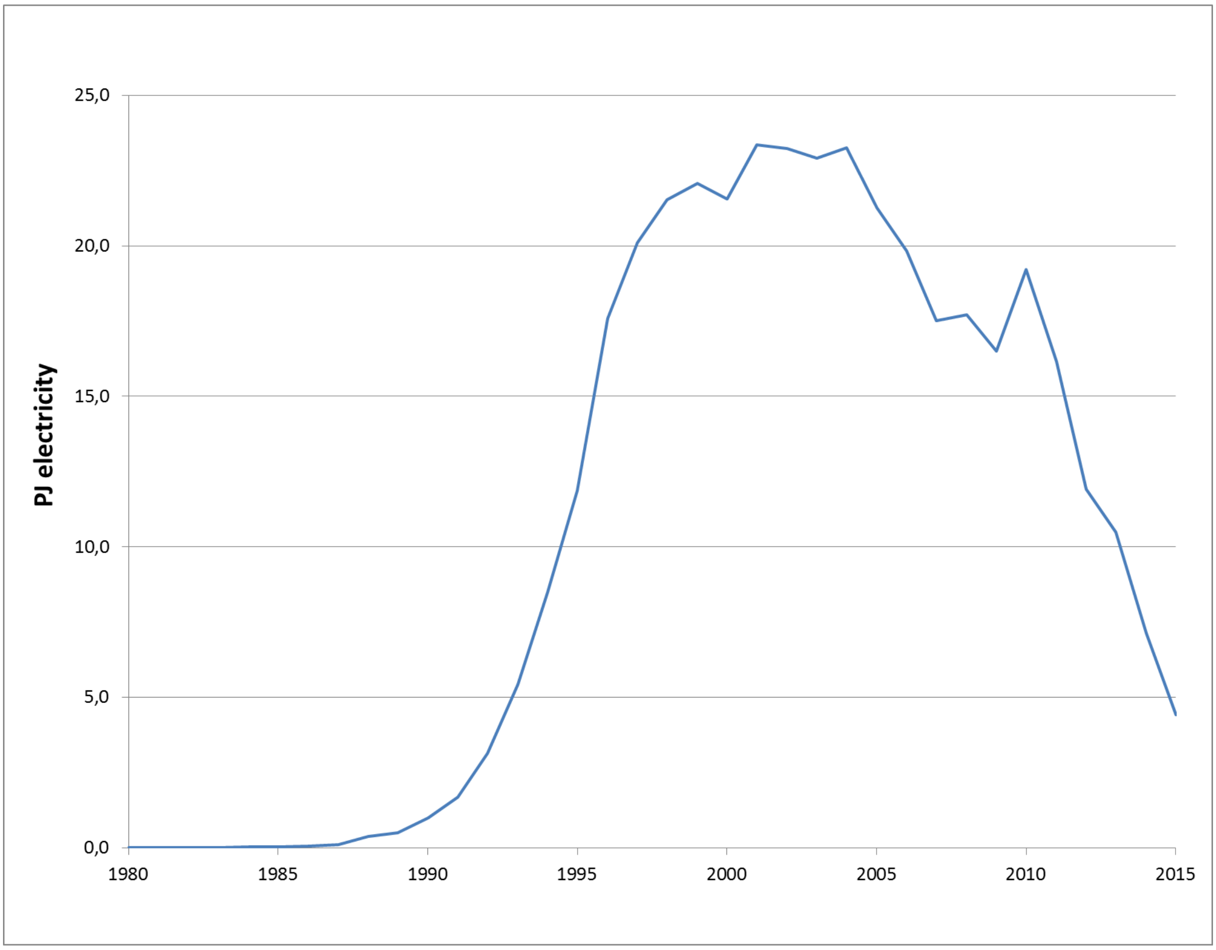


Figure 5: Yearly electricity productions at CHP at distributed DE plants, according to data from [32]*. Year 2015 has been derived from hourly data from the Danish TSO* [35]*.*

That there is a Phase 3 where CHP primarily delivers needed electrical capacity only in few hours, relates closely to the fact that the continued development of wind power and PV may reduce prices in the Scandinavian day-ahead market making CHP operation progressively less feasible. In a 100% renewable energy system, however there will still be hours where the fluctuating productions from RES are not able to cover inflexible electricity demands. So, an electrical capacity beside the capacity in wind turbines and PV is needed. This obvious consequence of developing wind power is also described in the Danish Transmission System Operator´s plans for 100% renewable energy in Denmark, which states that today's cogenerated 90 PJ of heat will in 2035 have gone down to 40 PJ and in 2050 have gone down to 5 PJ [36]. As shown in Figure 5**Error! Reference source not found.**, yearly electricity production at DE CHP has dropped dramatically in the last years, so the few hours of operation of CHPs at distributed DE plants make it difficult for these to survive, and if a new capacity payment is not decided, it is expected that the distributed CHP capacity will be reduced [37].

1.4 Needed optimization of daily operation of DE plants with large TES

Traditionally, the main task of the DE plants is to provide heating and cooling to cities. However, equipped with a combination of CHPs, HPs and TES, these flexible DE plants may furthermore have an important role in integrating intermittent power production [38]. The very different tasks of DE plants in the transition to a RES-based system call for these to be equipped with both large production and TES capacity [39]. A large CHP capacity is needed to supplement intermittent RES production at times of low RES production. Likewise, a large HP capacity is needed in the integration of intermittent RES production by primarily consuming electricity and producing heat during periods with high intermittent RES production - often with low prices during these periods [40]. The needed large TES capacity is closely related to the large CHP and HP capacity enabling these to detach productions from momentary thermal demands [39].

The operation of DE plants will often be market-based to efficiently participate in the integration of the intermittent RES production. This calls for the operators of these plants to determine and dispatch a daily operation schedule of the production units, that is to say that they must decide when to start and stop each production unit and decide at which load, they should be operated. This is denoted Unit Commitment (UC), and UC methods are different approaches to determining this operation.

In this thesis the UC methods are proposed divided into two significantly different groups; the analytic UC methods and the solver-based UC methods, even if some UC methods may have properties that places them in-between or outside these two main groups.

The solver-based UC methods are based on the minimization of an objective function – typically for DE plants the Net Production Cost (NPC) in an optimizing period of, say, 7 days. The NPC is the cost of covering heating and cooling demands factoring in a possible sale of electricity in these days. The minimization is subject to constraints, e.g. that there is no overflow in the TES, and is made by randomly choosing a UC for which the NPC is calculated. Then this UC will be iterated towards improved NPC while meeting constraints.

The analytic UC methods typically dispatch the daily operation according to priorities calculated for each time step and for each production unit in the optimizing period.
Thus, the first step to determine these priorities could be to calculate what the NPC of each production unit is in each time step, e.g. showing that CHPs produce cheaper heat in hours with high Day-ahead prices and HPs produce cheaper heat in hours with low Day-ahead prices.
Based on these calculated priorities typically organized in a priority list, an analytic UC method makes a UC for the optimizing period fulfilling the constraints, and subsequently calculates the NPC of the whole optimizing period this UC leads to.

In many cases a solver-based UC method is able to give a precise estimation of how close the found NPC is to an optimal NPC. However, as a starting point an analytical UC method does not reveal this. Zheng et al. [41] pointed out that there has been a revolution in the energy system UC research with the mixed integer programming (MIP), standing out from the early solution and modelling approaches, amongst others priority list methods, which in this report is considered one of the analytic methods. Zheng et al. [42] reviewed 30 papers, showing the large effort over the last decades in developing efficient methods capable of solving the energy system UC problem in real cases or at least for obtaining good solutions in reasonable computational times. Abujarad et al. [43] pointed out that the complexities in balancing electrical loads with generation have introduced new challenges in regards to UC. They conclude that the significance of the UC priority list methods relies on committing generation units based on the order of increasing operating cost, such that the least cost units are first selected until the load is satisfied and they conclude that the methods converge very fast but is usually far from the optimal UC. The authors further stress that the advantage of employing Mixed Integer Linear Programming (MILP) to solve the UC problem is that the MILP solver returns a feasible solution and the optimality level is known. The disadvantage of this method is that it often takes a long time to run and the calculation time grows exponentially with increasing problem size.

In recent years research has been somewhat but not entirely focused on balancing electrical loads using solver UC methods. For instance, Senjyu et al. [44] developed a new UC method, adapting an extended priority list, consisting of two steps. During the first step the new method rapidly obtains a UC solution disregarding operational constraints. During the second step the UC solution is modified using problem-specific heuristics to fulfil operational constraints. The method, however was for electricity systems only.

In some cases, research has also included the balancing of heating demands. Ommen et al. [45] presented an energy system dispatch model for both electricity and heat production of Eastern Denmark. They examined a system where HPs contribute significantly in balancing both electricity and heat production with their individual demands. Also, Mohsen et al. [46] proposed an optimal scheduling of CHP units of a distribution network with both electric and heat storage systems.

The above-mentioned UC research concentrated mainly on system-based balancing of electrical loads made by steam-based generators where ramping effects and maintaining system reliability are significant constraints when finding the least production cost. They are therefore concluding that analytic methods like the UC priority list methods are not useful. This conclusion could be true when optimizing the energy system across all actors in the energy system.

However, by introducing market-based operation of the energy system, the actors are divided into numerous companies that optimize their UC by optimizing their own biddings on the electricity markets. Market-based operation means here the DE plants perform UC according to changing electricity prices – as opposed to e.g. performing UC according to non-market prices like fixed feed-in-tariffs or according to heat demand. In the Nordic day-ahead market, for instance, market-based operation means that each DE plant at 12 o'clock each day has to bid into the Day-ahead market for each of the 24 hours tomorrow, both concerning selling electricity from the CHPs and buying electricity to the HPs. This bidding is made without any concern about the system balancing but with due concern to the TES contents at the DE plant. Similarly, DE plants may operate in the balancing market, which is operated with a shorter time lead.

The TSOs, responsible for the market-based system balancing of electrical loads, will often split the balancing tasks into three balancing markets namely Frequency Containment Reserves, Frequency Restoration Reserves and Replacement Reserves [47]. These balancing markets together with the two whole-sale markets (Day-ahead market and Intraday market) comprise the five markets that DE plants can choose between – with variation across different countries.

As mentioned earlier, when developing further intermittent RES production there will be little room for inflexible steam-based generators on these markets, and the TSOs will maintain system reliability by other means, e.g. by installing synchronous condensers [48]. Also, flexible gas-based units will be needed. DE plants are often characterized by having fast units that can start and stop within typically 15 minutes, making it less important to include ramping effects when calculating UC.

Typically, these production units will be operated on/off which is enabled by the large TES. The focus of a DE plant is to cover heating and cooling demands, whereas electricity supply has less importance, thus often being neglected when planning UC. The market-based operation of DE plants will often be reduced to the participation in one or two of the electricity markets. That simplifies the UC problem and brings analytical UC methods back as potentially attractive methods for calculating UC of the DE plants.

However, this has not yet been seen in research. In this literature review is only found solver-based methods for calculating UC at DE plants. Mohsen et al. [46], Rooijers et al. [49], Wang et al. [50] and Lahdelma et al. [51] made UCs for optimal day ahead scheduling of CHP using MILP. Thorin [52] et al. succeeded in obtaining UC for CHP using both MILP and Lagrangian relaxation obtaining solutions within reasonable times by a suitable division of the whole optimization period into overlapping sub-periods. Anand et al. [53] considered dual-mode CHPs and found that in this case evolutionary programming was the best method to solve the UC problem. Basu et al [54] in a similar way used genetic algorithms for the UC problem, Takada et al. [55] used Particle Swarm Optimization, Song et al. [56] used an Improved Ant Colony Search algorithm. Gopalakrishnan et al. [57] used a Branch and Bound Optimization method for economic optimization of combined cycle district heating systems. Abdolmohammadi et al. [58] used an algorithm based on Benders decomposition to solve the economic dispatch of CHP. Rong et al. [59] used Sequential Quadratic Programming to solve multi-site CHP UC planning problem. Sudhakaran et al. [60] integrated genetic algorithms and tabu search for economic dispatch of CHP, and found that it reduces the computation time and improves the quality of the solution. Basu et al. [61] used a Colony Optimization algorithm to solve the CHP UC problem and showed that this algorithm is able to provide a better solution at a lesser computational effort compared to Particle Swarm Optimization, Genetic algorithm and Evolutionary programming techniques. Vasebi et al. [62] studied a multiple CHP system and found that a Harmony Search algorithm performs well. Powell et al. [63] studied a polygeneration distributed energy system with CHP, district heating, district cooling, and chilled water thermal energy storage, and have found that a Dynamic Programming algorithm performs well.

Pavičević et al. [64] described simplifications with a purpose of reducing computation time that in most of the studied scenarios exceeds 45 min. Wang et al. [65] studied improved wind power integration by a short-term dispatch CHP model, and shown that after necessary linearization processes, the CHP UC problem can be solved efficiently and analytically by MILP. Romanchenko et al. [66] investigated the characteristics of interaction between district heating (DH) systems and the electricity system, induced by present and future electricity price, and developed a MILP model to make optimal operating strategies for DH systems. Lahdelma at al. [51] used a Power Simplex algorithm to study the CHP UC problem.

Carpaneto et al. [67] studied optimal integration of solar energy in a district heating network and by making appropriate linearization and piecewise linear functions succeeded in using a MILP to the UC problem. Bachmaier et al. [68,69] studied spatial distribution of thermal energy storages in urban areas connected to DH and used the techno-economical optimization tool “KomMod” to solve the UC.

1.5 Needed support schemes promoting necessary flexibility at DE plants

The optimal extent of flexible CHPs, HPs and TES at DE plants in a certain country must be determined in national or regional analyses, or it may even be a political decision. Subsequently, a support scheme should, at the lowest cost of support, promote this amount. Often the present and most likely the future electricity prices do not create sufficient feasibility for the CHPs, HPs and TES to be installed. Therefore, support schemes are required to provide the required capacity.

In several reports EU has dealt with the challenge of designing and reforming energy sector support schemes [70–72] and pointed out that support should be limited to what is necessary and the support schemes should be flexible and respond to decreasing production costs [70]. Furthermore, support schemes should be phased out as technologies mature [70], and unannounced or retroactive changes should be avoided as they undermine investor confidence and prevent future investments [70].

On the basis of its analysis of support schemes, the EU Commission recommends, that Feed-in tariff schemes are phased out and that support instruments are used that expose energy producers and consumers to market price signals such as Premium schemes [72]. However, Dressler [73] has pointed out that Premium schemes may enhance market power, favour conventional electricity production and may even hamper the increase in production from RES.

From a policy side, the EU Commission states that support is intended to cover the gap between costs and revenues, for which reason adequate revenue projections must be made beforehand, but also states that these projections of the needed level of support can be difficult to make ex-ante, since the support may interact with, for instance, electricity prices in a complicated manner [72]. Thus, an ideal method for assessing DE support schemes should be able to show and to quantify if the level of support of the chosen support scheme can be expected to lead to the appropriate amount of production and storage capacity at DE plants and at what support cost.

Two of the most widely used support scheme types are the Feed-in premium types and the Feed-in tariff types. The focus in this thesis has been on these two support scheme, which are introduced and reviewed in the next two sections.

1.5.1 The Premium support scheme

In its basic form, the Premium support scheme adds a premium to the wholesale electricity price in each hour. This simple support scheme has gained ground in recent years and is used as main support instrument in Denmark, the Netherlands, Spain, Czech Republic, Estonia and Slovenia [74], and premiums are usually guaranteed for a longer period, e.g. 10 up to 20 years. In this way the scheme provides long-term certainty when receiving financial support, which is considered to lower investment risks considerably. Premiums are applied in the case of support of biogas amongst other by Denmark, Italy and Slovenia. In Germany, the biogas plants with capacity larger than 750 kW_e are only offered premiums. In Slovenia, a market-premium scheme has been introduced for operators above 500 kW_e [75]. Schallenberg et al. [76] argue that Premium schemes can help create a more harmonized electricity market, effectively removing the difference between renewable and conventional electricity production.

Haas et al. [77] argue that, in principle, a mechanism based on a fixed premium/environmental bonus reflecting the external costs of conventional power generation can establish fair trade, fair competition and a level playing field in a competitive electricity market between RES and conventional power sources. They mention that from a market development perspective, the advantage of such a scheme is that it allows renewables to penetrate the market quickly if their production costs drop below the electricity-price-plus-premium. Therefore, if the premium is set at the 'right' level (theoretically at a level equal to the external costs of conventional power), it allows renewables to compete with conventional sources without the need for entering "artificial" quotas. Mezősi et al. [78] have in their cost-efficiency benchmarking of European renewable electricity support schemes found that the premium support schemes in Denmark are the most cost effective ones.

The EU has dealt extensively with support in more reports [70–72] and recommends using the Premium scheme as it exposes the DE plant to the hourly market prices. Furthermore, in EU´s Guidelines on State aid for environmental protection [79] it is required that Member States convert the existing administratively determined Feed-in Tariff or Feed-in Premium schemes to competitively determined Feed-in Premiums or Green Certificate support schemes for new RES-E installations from 2017.

However, it is noticeable that Schallenberg et al. [76] have found that a premium scheme can occasionally lead to overcompensation. This is based on studying the Spanish system. Similarly, Gawela et al. [80], studying system integration of renewable energy through premium schemes on the German market, found a risk of overcompensating producers and find that it is questionable if a premium scheme is gradually leading plant operators towards the market.

1.5.2 The Feed-in tariff

In most countries Feed-in tariffs are amongst the preferred choices of support schemes [19]. They are designed in different ways, but in this thesis the Triple tariff has been chosen to be analysed in depth.

Much research has been published studying the effect of Triple tariff support schemes. Østergaard [81] analysed the geographical distribution of electricity generation and concluded that the Triple tariff influenced the local CHP plants to be operated according to a certain fixed diurnal variation. Soltero [82] mentions the Danish Triple tariff when considering the potential of natural gas district heating cogeneration in Spain as a tool for decarbonisation of the economy. Fragaki et al. [83], studying the sizing of gas engine and TES for CHP plants in the United Kingdom, mention that the situation there resembles the Triple tariff electricity sales prices of the Danish system. Sovacool [84] mentions that the Danish Triple tariff made CHP operators being paid for their provision of peak power thus improving significantly the feasibility of investments in CHPs. Toke et al. [85] investigated whether the Danish Triple tariff could assist the implementation of CHP in the United Kingdom, arguing that this could help meeting its long-term objective of absorbing high levels of fluctuating RES.

Some articles describe simulation of energy systems based on the Danish Triple tariff without investigating the Triple tariff in depth. Lund [86] and Lund and Münster [87] studied large-scale integration of wind power into different energy systems using a reference scenario where the CHP plants produced according to the Triple tariff. Taljan et al. [88] studied the sizing of biomass-fired Organic Rankine Cycle CHP investigating the plant size being optimized against the Triple tariff. Gebremedhin [89] mentions the Triple tariff when looking into externality costs in energy system models. Heinz and Henkel [90] considered the Triple tariff in connection with a fuel cell population in the energy system. Dominković et al. [91] considered the application of feed-in tariffs in Croatia, and argued that feed-in tariff for pit TES will be of significance for the economic feasibility of investment. Østergaard [20] describes the capability in EnergyPLAN [92] to simulate the operation of national energy systems, where CHP plants are operated according to a fixed Triple tariff system. Schroeder et al. [93] mention that a Triple tariff system increased CHP´s integration into electricity markets. Hernández [94] studied photovoltaic in grid-connected buildings, investigated single, double and Triple tariff systems in Spain.

1.6 Estimated yearly investment in production capacity at German DE plants

The need for energy system simulation tools to analyse the investment in and operation of energy production units and energy stores at DE plants in a certain country is closely related to the amount of these to be installed. In this section the yearly investment in production capacity at DE plants in Germany is estimated.

The heating sector in Germany plays a key role in delivering the energy transition (Energiewende). With a demand for heating of 1500 TWh it accounted for more than 50% of final energy consumption in Germany in 2013, and total heat generation costs in Germany was in 2014 €118 billion [95].

The accounting firm PwC estimates that it will hardly be feasible to reduce German carbon emissions by between 80% and 95% of 1990 level by 2050, if the German decarbonisation strategy currently pursued in the heating sector is not adjusted [95].

The market share of district heating of Germany's residential heat sector is 13.8%, equal to the average market share of district heating in the rest of EU. Total heat supply in the EU was 11.8 EJ (3278 TWh) in 2010, where district heating supplying EU's buildings is today 13% [11].

While the market share leaves room for further growth, Germany still remains the biggest market for district heating and cooling in the EU in terms of absolute figures. District heating production capacity is 51379 MW_{th} at 1372 district heating plants, and 10 mio. citizens are served by district energy [96].

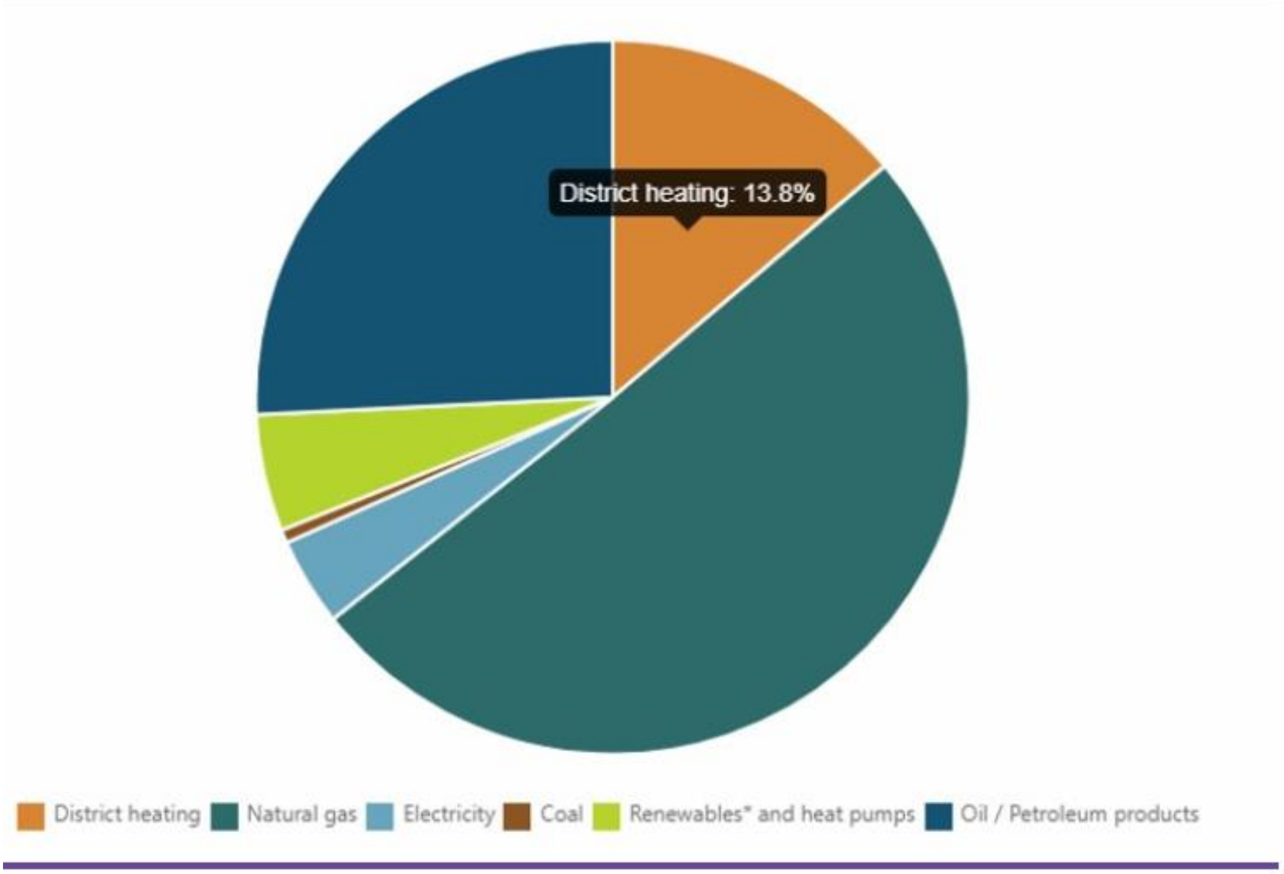


Figure 6: Composition of the origin for heat supply to residential and service sector buildings in Germany [96].

District energy in Germany has to be seen in the perspective of the German political goals [97]:

- 40 - 45 % share of renewables to be reached in electricity consumption by 2025
- In 2022 the remaining nuclear power plants are to be shut down
- 40 % of greenhouse gas emissions are to be reduced by 2020 (from 1990 levels)

In this estimation made in this section it is assumed that the results shown in Section 1.1 are applicable for Germany, concerning that a 30-40% reduction of the existing heat demand is socio-economic feasible, that approximately 50% of the remainder should be covered by DE and that this development of DE will reduce heating and cooling costs with approximately 15%. It is therefore assumed likely that Germany will decide to promote this development of DE. With these assumptions and an assumed typical investment in CHP and HP capacity of 0.7 mio. EUR/MW_{th}, Table 1 shows an estimated total yearly investment in new production capacity at DE plants in Germany of 6050 MW_{th} and a yearly investment cost of more than 4 billion EUR per year.

Present amount of heat demand in Germany	1500	TWh-heat
Present heat demand, after reduction with 35% through better efficiency	975	TWh-heat
Half of this to be served in the future by district energy	**488**	**TWh-heat**
Present heat demand (13,8%) served by district energy (DE)	207	TWh-heat
Present DE production capacity	51379	MW_{th}
Life time of DE production capacity	20	years
Investment cost in DE production capacity	0.7	mio. EUR/MW_{th}
Yearly investments in new production capacity at existing DE plants	2569	MW_{th}
	1.80	**billion EUR per year**
Yearly investments in new production capacity at new DE plants	3481	MW_{th}
	2.44	**billion EUR per year**
Total yearly investments in new production capacity at DE plants	6050	MW_{th}
	4.24	**billion EUR per year**

Table 1: Estimated total yearly investments in new production capacity at DE plants in Germany.

1.7 Scope and research questions for this thesis

A wide range of tools for DE plants are needed, among other tools ranging from supervisory control and data acquisition tools (SCADA) for controlling the instantaneous operation of the production units and the operation of the grids (e.g. the heating and cooling grids) to tools for handling financial accounting and cash flow at the DE plants.

However, this dissertation concerns the development of next generation energy system tools for simulating DE plants. The scope for this development has been delimited to those tools needed for the following tasks in DE plants:

- Investment analysis for comparing very different alternatives for complex future DE plants operating in complex energy markets subject to complex support schemes and energy taxes (as dealt with in [39] and [98]).
- Daily or short-term planning of operation, also when this operation will be determined from biddings in the electricity and fuel markets and affected by availability of fluctuating energy sources, large energy stores and restricted capacities in the heating, cooling and electrical grids.

Thus, the focus is on heating, cooling and electricity demands in more buildings supplied from a DE plant, typically equipped with energy stores, as heating, cooling, fuel or electricity stores. The operation is often market-based and optimized across different energy types, which each may be subject to restricted grid capacities between the DE plants and the buildings. The focus in the development is on optimizing plant and grid operation. However, optimization across plant, grids and buildings have in some detail been dealt [23].

The main research question is:
Is it possible to develop a tool which is able to analyse and compare sufficiently detailed very different alternatives for DE plants providing heating and cooling?

For such a tool to be appropriate for practitioners, it has to offer an acceptable time setting up models, an acceptable calculation time and it should use a calculation method understandable by the managers of the DE plants.

To make this research question operational as well as to delimit it, three sub questions are formulated:

Sub question 1: *How can the optimization of market based daily operation of DE plants with large TES be solved?*

Sub question 2: *How can a coordinated investment in production and storage capacity at DE plants be analysed?*

Sub question 3: *How can the effect of support schemes promoting necessary flexibility at DE plants be analysed?*

In this PhD study the specification of the requirements for next generation energy system tools for simulating DE plants has primarily been made considering the conditions in Germany, Denmark and UK. These three countries have been compared on key figures in Table 2. The conditions in these three countries are similar, only when it comes to Area per capita Denmark has nearly the double area (7368 m^2), which in some cases will make it easier to establish e.g. large place requiring solar collectors and thermal stores. For comparison, area per capita is 58,462 m^2 in Norway, 41,616 m^2 in Sweden, 55,455 m^2 in Finland and 28,251 m^2 in the US [99].

Key figures	**Germany**	**Denmark**	**UK**
Population (million)	82.70	5.70	65.60
Total Final Consumption per capita (MWh/cap)	34.94	27.16	21.92
Electricity consumption per capita (MWh/cap)	6.92	5.81	4.99
Emissions per capita (tCO_2/cap)	8.93	5.63	5.99
Gross Domestic Product per capita (1000 EUR/cap)	36.36	38.18	32.68
Area per capita (m^2)	4220	7368	3689

Table 2: Comparison of key figures for selected countries [99]. *Data are from 2015.*

1.8 Thesis structure

This introduction describes the societal benefits of District Energy, the needed flexibility of DE plants, the changing roles of CHP at DE plants when developing renewable energy, the needed optimization of daily operation of DE plants with large TES, the needed support schemes promoting necessary flexibility at DE plants, the estimated yearly investment in production capacity at DE plants as well as the scope and research questions for this dissertation.
Section 2 defines the methodology used.

The next three sections deal with the three research sub questions in turn. Section 3 deals with how to mathematically solve the optimization of market based daily operation of DE plants with large TES. Section 4 deals with how to analyse coordinated investment in production and storage capacity at DE plants. Section 5 deals with how to analyse support schemes promoting necessary flexibility at DE plants. These sections are mainly based on two published and one under revision article each.

Section 6 discusses the need for further research in next generation generalized energy system simulation tools for district energy, and Section 7 concludes on the question if it is possible to develop one generalized tool which is able to analyse very different alternatives for DE plants providing heating and cooling.

2. Methodology

When choosing the methodology used in this PhD project, it is to be kept in mind that it deals with the development of next generation energy system tools for simulating DE plant, delimited to those tools needed for the following tasks in DE plants:

- Investment analysis for comparing very different alternatives for complex future DE plants operating in complex energy markets subject to complex support schemes and energy taxes.
- Daily or short-term planning of operation, also when this operation will be determined from biddings in the electricity and fuel markets and affected by availability of fluctuating energy sources, large energy stores and restricted capacities in the heating, cooling and electrical grids.

In this section is described the methodology used to work with this development.

2.1 Literature review

The framework for the work is made through a comprehensive literature review in Section 1.
The review has started with a historical review, with the ambition of identifying a sufficiently broad range of aspects of the tasks mentioned above.
The literature review has been divided into five sections:

- Societal benefits of District Energy
- Needed flexibility of DE plants
- Optimization of daily operation of DE plants
- Support schemes promoting necessary flexibility at DE plants
- Estimated yearly investment in production capacity at DE plants

The author has 18 papers and articles at www.scopus.com, being main author of three papers and coauthor of the remainder. These papers and articles are all relevant for the topic of this PhD project. Most of them has been published before this PhD study and the work with these pre study publications have been inspired to keywords in each of the sections. The keywords have been used for search in ScienceDirect, Scopus, Google Scholar and Google.

Furthermore, a more systematic approach has been used to identify aspects contained in the research subject, used for identifying relevant search words, being used for block searching in the databases:

- Compendex
- Scopus
- Proquest

2.2 Case studies

In the PhD study has been developed a method for analysing coordinated investments in production and storage capacity at DE plants and developed a method for comparing the effect of support schemes at DE plants. At its best when using or verifying the methods in a certain country, all existing and expected future DE plants in this country should be analysed. This is outside the scope of this PhD study to do such a comprehensive analysis. Therefore, this PhD study has been limited to complex natural gas fired generic DE plant cases.

When choosing these DE plant cases, Flyvbjerg´s work on the methods for making Case-Study Research [100] has been taken into account, as mentioned in Table 3.

Flyvbjerg´s emphasis on misunderstandings About Case-Study Research	**Flyvbjerg´s understandings About Case-Study Research**
One cannot generalize on the basis of an individual case; therefore, the case study cannot contribute to scientific development.	*One can often generalize on the basis of a single case, and the case study may be central to scientific development via generalization as supplement or alternative to other methods. But formal generalization is overvalued as a source of scientific development, whereas "the force of example" is underestimated.*
The case study is most useful for generating hypotheses; that is, in the first stage of a total research process, whereas other methods are more suitable for hypotheses testing and theory building.	*The case study is useful for both generating and testing of hypotheses but is not limited to these research activities alone.*
The case study contains a bias toward verification, that is, a tendency to confirm the researcher's preconceived notions.	*The case study contains no greater bias toward verification of the researcher's preconceived notions than other methods of inquiry. On the contrary, experience indicates that the case study contains a greater bias toward falsification of preconceived notions than toward verification.*

Table 3: Flyvbjerg´s work on the methods for making Case-Study Research [100]

Furthermore, Flyvbjerg mention that strategic choice of case may greatly add to the generalizability of a case study. In this PhD study it has been tried to comply with a strategic choice, when choosing the cases, by taking into account how DE plants is likely to be equipped with large CHPs, HPs and TES in a renewable energy system.

Furthermore, the reproducible research paradigm has been pursued in this study, so that even if it is complex plants considered, the description of these are sought to be so generic described, that it allows readers reproducing with minimal effort the results obtained. Therefore,
it has been assumed that partial load performance of production units is strictly linear. As mentioned by Ommen et al. [45] this simplified assumption will lead to a minor error when dealing with operation of a real plant, but is not considered to be a substantial problem when the generic DE plant is equipped with large TES.

2.3 Simple energy balance method

Throughout the analysis in this study only simple energy balance calculations have been made for the considered DE plants. A broader analysis of the DE plants would include hydraulic calculations, as well as flow and temperature modelling. Energy balance is an obvious starting point when the ambition is the development of a generalized tool, which is able to analyse very different alternatives for DE plants providing heating and cooling. There has to be energy balance in every time step of a chosen optimizing period. However, it is to be kept in mind that no hydraulic constraints have been included and energy stores has been assumed to be split into two well defined temperature zones.

2.4 DE plants participating only in the Day-ahead electricity markets

In the comparison of unit commitment methods at DE plants, development of a method for analysing coordinated investments in production and storage capacity at DE plants and development of a method for comparing the effect of support schemes at DE plants, only participation in the Day-ahead electricity markets have been assumed.

However, in the future DE plants are assumed to participate across more of both existing and future electricity markets. A more elaborated analysis of the value of large production and storage capacity requires simulations across more markets, which is rather tedious, because it has to take into account the organization of these markets, when it comes to e.g. gate closures and price settlements. The need for further research in DE plants participating across more markets is described in section 6.1. The complexity of simulating DE plants participating across more markets is illustrated Figure 7, illustrating the organization of the electricity markets in West Denmark, having three balancing markets namely Frequency Containment Reserves, Frequency Restoration Reserves and Replacement Reserves and two whole-sale markets (Day-ahead market and Intraday market).

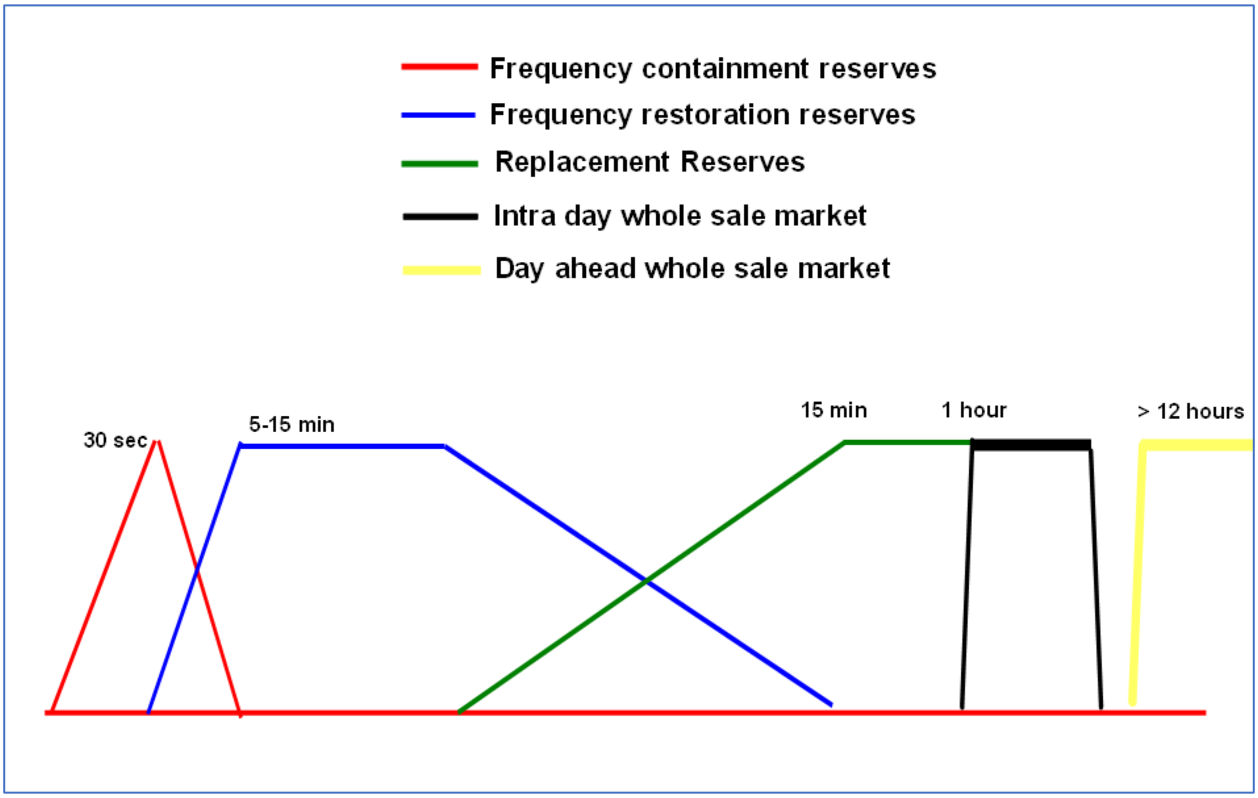


Figure 7: ACER´s [47] general framework for the organization of thee electricity markets as implemented in West Denmark.

2.5 Tools used in the analysis and methods

The tools used are energyPRO, VBA-coding in Excel, Phyton and Gurobi Solver.

2.5.1 The energy system analysis tool energyPRO

It is chosen to use energyPRO [34] in the developed method for analysing coordinated investments in production and storage capacity at DE plants and the developed method for comparing the effect of support schemes at DE plants. The reason for this choice is described in detail in [39], and summarized below.

In energyPRO the time step may be 1 hour or less allowing a calculation of the hourly cash flow. It allows the use of indexes describing e.g. the development of demands for heating and cooling and the development in prices over the years, which implies that the operation of the production units between the years may change e.g. due to changed economic conditions.

energyPRO is based on analytical programming based on pre-defined methods for finding optimal operation – either through marginal production costs of units or through user-defined priorities. This analytical method is described more thoroughly by Østergaard et al. [23]. An important reason for using energyPRO, is it is widely used by consultants to analyse investments in DE plants [101]. That brings the method for assessing support schemes close to how investment decisions are made. Furthermore, energyPRO is widely used for research, e.g. Sorknæs et al. have applied energyPRO to study the treatment of uncertainties in the daily operation of combined heat and power plants [102]. Østergaard et al. used energyPRO to optimize the sizing of booster heat pumps and central heat pumps in district heating [23] and to assess the economy of such systems [103]. Fragaki et al. applied energyPRO to study the economic sizing of a gas engine and a thermal store for CHP plants in the UK [104,105]. Streckienė et al. studied the feasibility of CHP-plants with thermal stores in the German Day-ahead market [106] and Østergaard studied heat and biogas stores' impacts on RES integration [107].

2.5.2 VBA-coding in Excel

VBA in Excel is an object-oriented application, that give full flexibility in analysing energy systems. In this study it has been used in the developed method for analysing coordinated investments in production and storage capacity at DE plants and the developed method for comparing the effect of support schemes at DE plants. An example of the VBA-coding made in the developed methods are shown in Annex I.

2.5.3 Python

Python is a programming language at the same level as VBA-coding in Excel. The reason for using it in this PhD study is primarily that is makes it easy to formulate object functions and constraints necessary for calling solvers. It has been used for comparing unit commitment methods at DE plants. The developed code is shown in Annex II, calling the solver Gurobi Optimizer.

2.5.4 Gurobi Optimizer

The Gurobi Optimizer is a commercial state-of-the-art math programming solver able to handle major problem types [108] and has in this PhD study been used as one of the methods used to calculate unit commitment at DE plants. It allows to solve among other MILP problems, defined by linear object functions and defined by constraints, as described in detail in [109]. The starting point for this solver is linear programming, that is able to be solved mathematically. However, it is a commercial solver, and it is not revealed in the documentation [108], how the linearity is converted to integer constraints.

2.6 Supporting input

The methods developed in this thesis have benefitted from and build upon the methods met in more of the completed PhD courses, as exemplified below. Moreover, a stay at EMD and dialogue with students have made important input to this PhD study.

2.6.1 Electricity Market and Power System Optimization

In this PhD course we were, amongst other things trained in UC problems, formulating these UCs with proper objective functions and constraints using solvers in GAMS (General Algebraic

Modelling System) [110] for solving the UCs. Professor Andres Ramos [111] from Comillas Pontifical University in Spain, delivered the main training.

2.6.2 Optimization Strategies and Energy Management Systems

This PhD course recognised and formulated different optimization problems in planning, operation and control of energy systems, and how to solve them using existing software and solvers such as MATLAB, GAMS, and Excel. Several illustrative examples and optimization problems were made, ranging from the classical optimization problems to the recent Mixed integer nonlinear programming (MINLP) models proposed for the optimization of integrated energy systems (such as residential AC/DC microgrids), including heuristics and meta-heuristics methods. Professor Moises Graells (Technical University of Catalonia) and Associate Professor Eleonora Riva Sanseverino (University of Palermo) completed major parts of this course.

2.6.3 Scientific Computing Using Python

Besides training in scientific computing using python, this PhD course introduced the reproducible research paradigm that has been pursued in this thesis. As mentioned in the course, all too often, articles do not describe all the details of an algorithm and thus prohibit people from reproducing with minimal effort the results obtained. Both the reproducibility of data and algorithms was discussed. The effort required to make research reproducible is compensated by a higher visibility and impact of the results, by convincing readers that the result is correct.

Associate Professor Thomas Arildsen from Aalborg University´s PhD Consult handled the teaching. Furthermore, he assisted in setting up the MILP problem in this thesis in Gurobi Optimizer interfaced by Python.

2.6.4 Photovoltaic Power Systems

In this PhD course Associate Professor Derso Sera and Associate Professor Tamas Kerekes from Aalborg University educated us in the methods for modelling PVs, being further elaborated on in Section 6.

2.6.5 Storage Systems based on Li-ion Batteries

In this PhD course, Dr. Daniel Stroe and Dr. Erik Schaltz from the Department of Energy Technology, Aalborg University, Aalborg, educated us in this PhD course in methods of performance testing and modelling, ageing, performance degradation and lifetime estimation of batteries, as further elaborated on in Section 6.

2.6.6 DE plants consultancy

Through my stay these three years at the Energy Systems Department at the company EMD International A/S, I have met a wealth of DE plants being analysed as part of consultancy tasks and project work.

2.6.7 Fruitful discussions with students

Being responsible together with Poul Alberg Østergaard for the Energy System Analysis course offered by The Sustainable Energy Planning Research Group, Department of Planning, Aalborg University, I handled the teaching concerning optimal operation of CHP and tri-generation plants and energy storage in energy systems, as well as the teaching of how to make a sustainable energy system analysis in the modelling language Visual Basic for Application (VBA). The students' wealth of very different examples was certainly a challenging inspiration to the work in this thesis concerning having only one tool being able to analyse very different alternatives for DE plants.

3. Comparison of unit commitment methods at DE plants

In the literature review has been demonstrated that a common conclusion hitherto has been that UC based on analytic methods is not useful. However, the market-based operation of DE plants often being reduced to participation in one or two of the electricity markets, simplifies the UC and brings analytic UC methods back as potentially attractive methods for DE plants. This is demonstrated in this section by making a complex generic DE plant yet so simplified that a MILP method is able to deliver optimal UCs. An advanced analytic UC method for district energy plants is proposed and the comparison of the UCs made by this method with the optimal UCs shows that the method delivers fully adequate UCS needed for daily operation planning, yearly budgeting and long-term investment analysis for this DE plant. The novelty in this comparison is thus that it brings analytic UC methods back as potential attractive methods to be used at DE plants.

The description in this section is based on the appended article II: *Analytic versus solver-based calculated daily operations of district energy plants*, which is in the second review round at the time of writing (December 31st 2018). Much of the text in this chapter is copied verbatim from this manuscript, while many of the more general aspects in the paper are left out here.

Technical and financial data of the complex generic DE plant being used for the comparison is shown in Table 4.

CHPs		
Electrical efficiency	44.0%	
Heat efficiency	48.9%	
Total efficiency	92.9%	
Fuel input	13.65	MW
Electrical power	6.00	MW
Heat power	6.67	MW
Variable operation costs	5.40	EUR/MWh_e
Start costs of CHP´s	30	EUR/start
HPs		
COP	3.5	
Electrical consumption	1.91	MW
Heat power	6.67	MW
Variable operation costs	2.00	EUR/MWh_{heat}
Start costs of HP´s	10	EUR/start
Gas boilers		
Heat efficiency	103.0%	
Heat power	15.00	MW
Fuel input	14.56	MW
Variable operation costs	1.10	EUR/MWh_{heat}
TES	59.24	MWh_{heat}

Table 4: Technical and financial data on CHP, HP, TES and existing boilers (2016-prices) used in the test of the UC methods, based on typical values from [112]*.*

The DE-plant participates in the Day-ahead market and as shown in Figure 8 only the CHPs and HPs have access to store heat in the TES. The capacities of the units are shown in Figure 8.

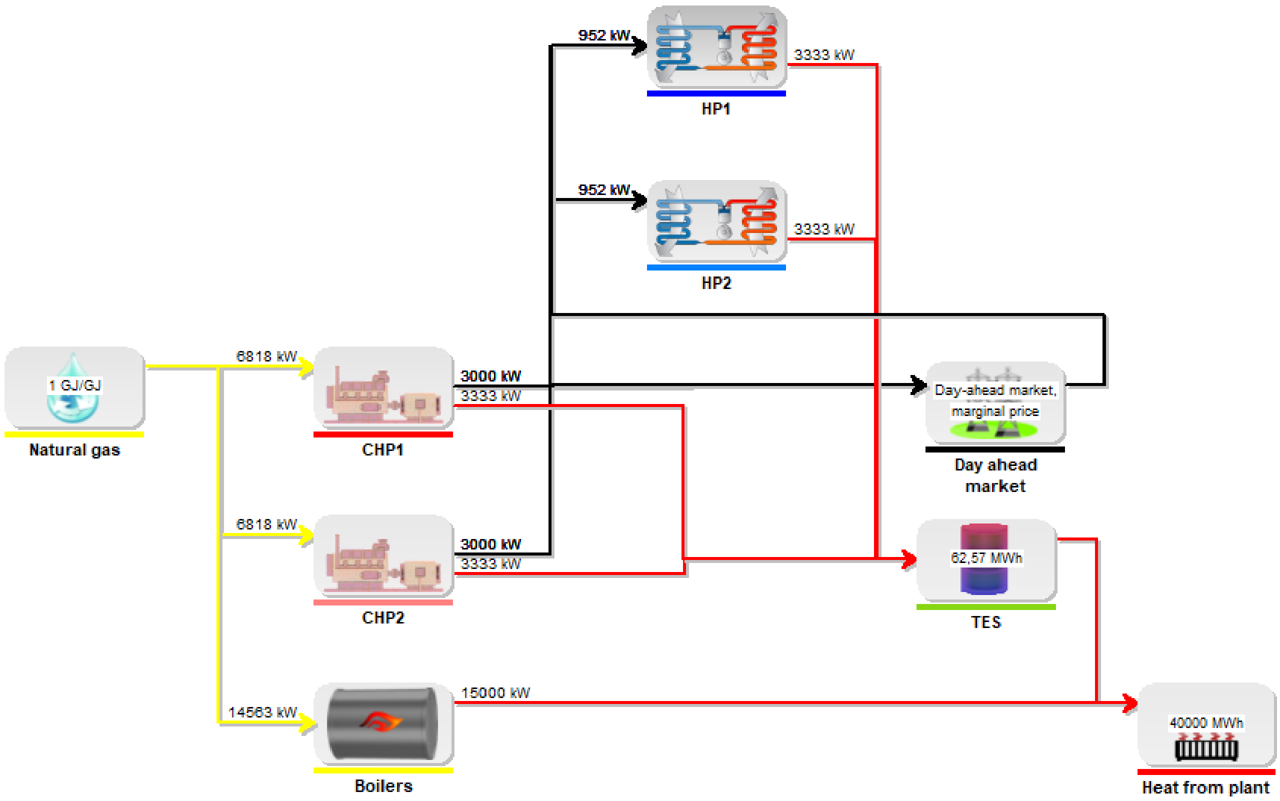


Figure 8: The generic DE plant case consisting of CHP, HP, boilers and TES units.

3.1 The UC methods to be compared

Loads to be satisfied at DE plants are primarily heat- and cooling loads, hence the focus is on heating and cooling production costs. As the CHPs and HPs are assumed to be traded on the Day-ahead market, these production costs will change from hour to hour. The two analytic UC methods and the solver UC method to be compared are described in this section.

3.1.1 The advanced analytic UC method

The description of the advanced analytic UC method in this section is delimited to a description on how to solve the UC at heat-only DE plants as the plant described Figure 8, but the method may be generalised to more complex DE plants.
The first step is for each production unit in each time step in the optimization period, to attribute a priority number reflecting the operating cost of 1 MWh_{heat}. The priority number for e.g. a CHP is the cost of producing 1 MWh_{heat} reduced with the value of the associated produced electricity in that time step, referred to as the Net Heat Production Cost (NHPC). In this case it is assumed that the produced electricity is sold on the Day-ahead market and that the time step is 1 hour, thus the

priority number for e.g. a CHP in a certain hour depends on the price on the electricity Day-ahead market (the spot price). Similarly, the NHPC of the HP depends on the electricity spot price.
The Technical and financial data given in Table 4 result in the priority numbers shown in Figure 9 as a function of the hourly electricity Day-ahead market price. The figure indicates that for all electricity spot prices the NHPC for the CHPs and HPs are lower than the NHPC of the boilers, which are independent of the spot price. Furthermore, it is seen that up to approximately a spot price of 40 EUR/MWh$_{e,}$ the NHPC of the HPs is lower than these of the CHPs.
An ordered priority list (PL) is made of these priority numbers, with the lowest priority numbers firstly stated on the list and where each of these priority numbers links to a certain hour and production unit. Thus, if a plant has five production units as in this case and the simulation is hourly made over a one-year period, the PL contains 5*8760 priority numbers.

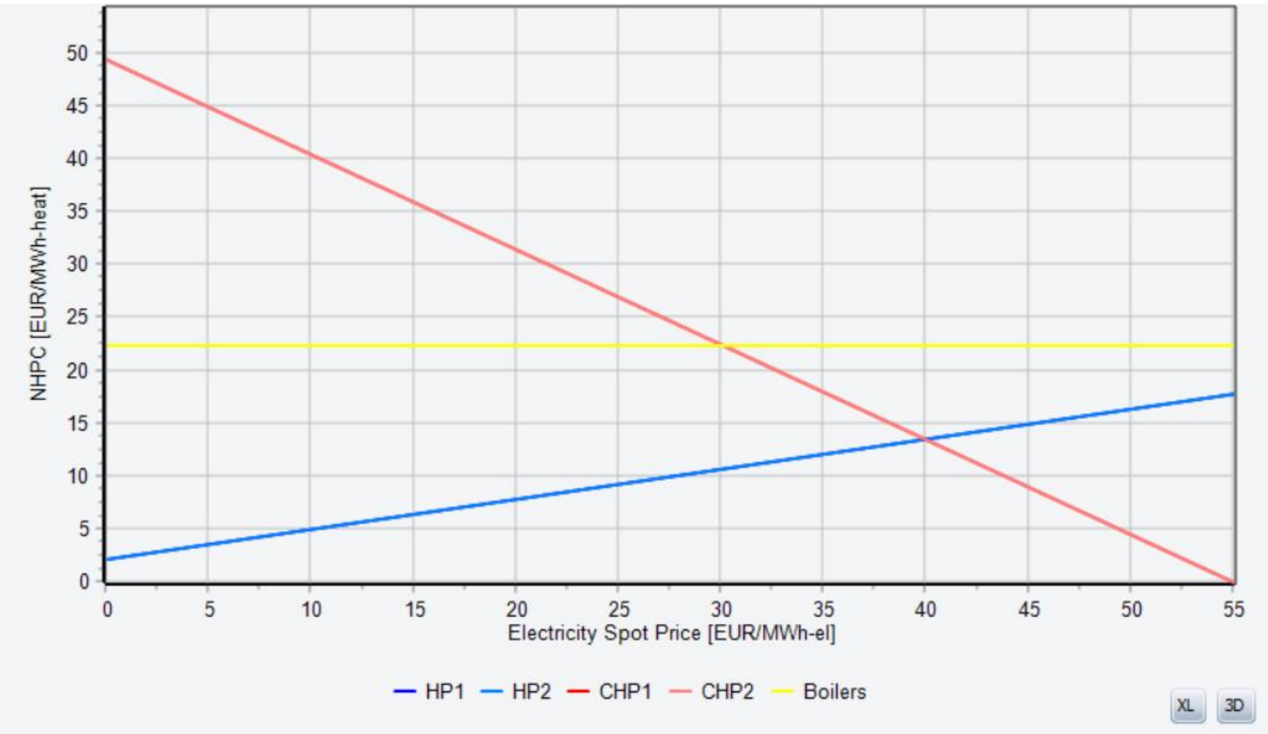


Figure 9: Specific NHPC of the production units as described in this section, as function of the electricity spot price on the Day-ahead market. Starting costs are not included.

Each production unit at a DE plant typically has associated starting costs and may e.g. have constraints regarding minimum operation period duration. It could e.g. be a minimum of 3 hours of continuous operation of CHPs, which is relevant when making block bids on the Day-ahead market. Similarly, minimum stop periods could be a constraint. The minimum operation periods have been included when creating an additional list of start blocks in parallel to the PL.
Each start block contains hours which is at least equal to the minimum length of an operation period. To each start block is associated a priority number which is calculated as the average NHPC of the production unit in the hours in the start block, and to the average NHPC is added the starting cost of the production unit divided by the amount of heat produced by the production unit in the start block. Thus, if a project has 5 production units and the simulation is hourly during a one-year period and the minimum length of operation periods for all production units is 3 hours,

there will be at least 5*(8760-2) different 3-hour start blocks. It is possible to also include larger start blocks e.g. 4-hour start blocks or 6-hour start blocks, which will significantly increase the number of start blocks if not only increasing the calculation time but also increasing the optimality of the UC solution. These start blocks are ordered in a Start Block List (SBL) with the start blocks with the lowest priority first.

After having created the PL and SBL, the UC starts taking the first start block in the SBL and try if it is possible to commit this when considering the restrictions in the energy stores and transmission lines. If it is not possible to commit this start block, the next start block is tried to be committed. This continues until a start block is committed.

When a start block is committed, the priority number of the next start block in the SBL is registered. Then the PL is checked up to the priority number of the next start block to see if some of the priority numbers are linked to an hour which may expand the committed start block. Before an expansion of an already planned production period is accepted, it must be carefully checked to ensure that it does not disturb already planned future productions. This is checked in an iterative way, by chronological checking from the hour of expansion if this new production in that hour together with the already planned future productions still fulfils the restrictions in the energy stores and transmission lines. When these expansions of operating periods are exhausted from the PL, the next start block in the SBL is tried committed. This continues until a start block in the SBL is successfully committed. Then again, the PL is checked for possible expansion of all already planned operations.

If the expansion of operation periods results in a distance between two operation periods equal to the length of a start block, the start block fitting into the gap between these two operation periods, will have its priority number recalculated improving the priority number, because if successfully committed it will remove a starting cost, as the two operation periods have become one coherent operation period. The start block will be moved up in the SBL.

This UC continues until the end of the SBL, but the steps go faster and faster because the next start block on the list might be deemed illegal and skipped as it is either overlapping or too close to already planned operation periods or in conflict with minimum stop periods.

An example of the advanced priority list UC for the DE plant described is shown in Figure 10 for 7 days in September. The upper panel shows the electricity price in the Day-ahead market. The heat and electricity production and consumption are shown in the next two panels. The bottom panel shows the contents in the TES.

It is seen that the CHPs are mainly producing during hours with high spot prices and the HPs are mainly producing during hours with low spot prices. The boilers are not producing, which is in good compliance with the NHPCs shown in Figure 9, where the cost of producing heat in boilers is the most expensive one for all spot prices.

The starting point for comparing the quality of UCs is their NHPCs for the chosen optimization period, thus the UC with the lowest NHPC is considered the best. The reason for not choosing the operation income of the optimization period when comparing UCs is that e.g. the revenues from the sale of heat is the same for all UCs as long as the heat demand is covered. An example of the UC for an optimization period, where the UC is calculated using the advanced analytic UC method is shown in Figure 10, and the associated NHPC is shown in Table 5.

Figure 10: An example of the UC at the DE plant during 7 days in September calculated using the advanced analytic UC method.

Net Heat Production Cost from 01-09-2016 00:00 to 29-09-2016 00:00								
(All amounts in EUR)								
Operating Expenditures								
Purchase of electricity HP1	282.7	MWh_e				6 941		
Purchase of electricity HP2	212.3	MWh_e				5 137		
Variable operation costs of HP1	989.9	MWh_{heat}	at	2.0	=	1 980		
Variable operation costs of HP2	743.3	MWh_{heat}	at	2.0	=	1 487		
Fuel costs	752.1	GJ	at	5.6	=	4 212		
CO2 quotas	42.6	ton CO_2	at	8.0	=	341		
Variable operation costs of CHP1	69.0	MWh_e	at	5.4	=	373		
Variable operation costs of CHP2	21.0	MWh_e	at	5.4	=	113		
Variable operation costs of boilers	4.5	MWh_{heat}	at	1.1	=	5		
Start costs of CHP1	6	starts	at	30.0	=	180		
Start costs of CHP2	2	starts	at	30.0	=	60		
Start costs of HP1	33	starts	at	10.0	=	330		
Start costs of HP2	27	starts	at	10.0	=	270		
Total Operating Expenditures								**21 428**
Revenues								
Sale of electricity CHP1	69.0	MWh_e				3 234		
Sale of electricity CHP2	21.0	MWh_e				1 026		
Total Revenues								**4 260**
Net Heat Production Cost								**17 168**

Table 5: The NHPC at the DE plant during the first 28 days in September calculated using the advanced UC priority list method.

3.1.2 The simple analytic UC method

As mentioned by Abujarad et al. [43] the basics of UC priority list methods are to commit generation units based on the order of increasing operating cost, such that the least cost units are firstly selected until the load is satisfied. In the simple UC priority list method, it is chosen that the production units are ranked, and the highest ranked production unit is tried to be committed to the entire optimizing period respecting the limited size of the TES. The next highest ranked production unit is then tried, on top of the first one, to be committed to the entire optimizing period, continuing this way to add production units until the heat demand is covered

3.1.3 The MILP solver UC method delivering the optimal UC solutions

The MILP method is a formulation of the UC with start-up and shut-down constraints, described by Gentile et al. [113]. Decision variables are established for each of the five production units and the TES. The two CHPs and the two HPs are each binary as no partial load operation is allowed. For the boiler and TES, the decision variables are continuous with upper bounds equal to the maximum capacity.

The objective function to be minimized is the NHPC for the optimizing period. An example of the calculation of the NHPC is shown in Table 5, and is calculated as:

$$NHPC = \sum PurchaceOfElectricity + \text{VariableOperationCosts} + \text{FuelCosts} + \text{CO2Quotas} + \text{Startcosts} - \text{SaleOfElectricity}$$

The technical and economic conditions for the calculation of the NHPC is given above.

There are included the following constraints.

To each of CHP1, CHP2, HP1 and HP2 is connected three decision variables ensuring that the minimum length of operation periods and stop periods are equal to three hours, as shown for CHP1:

CHP1[i]	Unit commitment Boolean {0;1} being true for CHP1 in operation in this time step
CHP1start[i]	Boolean {0;1} true for CHP1 in operation in this time step and not in operation in the time step before.
CHP1stop[i]	Boolean {0;1} true for CHP1 not in operation in this time step and in operation in the time step before.

Constraint 1: General connection between unit Booleans.

$$CHP1[i] - CHP1[i-1] = CHP1start[i] - CHP1stop[i]$$

Constraint 2: Minimum length of operation periods - here three hours.

$$3 \cdot CHP1start[i] \leq CHP1[i] + CHP1[i+1] + CHP1[i+2]$$

Constraint 3: Minimum length of stop periods – here three hours.

$$CHP1stop[i] + CHP1stop[i+1] \leq 1 - CHP1[i+2]$$

The use of the TES meets the heat balance constraint.
Storage[i]+3.333*(CHP1[i]+CHP2[i]+HP1[i]+HP2[i]) + Boilers[i] – HeatFromPlant[i]=Storage[i+1]

Storage is the content in the TES in the beginning of each time step measured in MWh. The other symbols refer to the symbols used in Figure 8 and are measured in MW. The chosen time step is 1 hour, and it is not necessary to multiply the other symbols with the time step.

3.2 Result of the tests

The focus in this thesis is the development of UC methods needed for daily operation planning, yearly budgeting and long-term investment analysis of DE plants. When planning the daily operation for today or tomorrow, also operation during the next days has to be taken into account, as these plants are often equipped with large TES. Thus, using the storage capacity today decreases the possibility to store heat the subsequent days even if production conditions (prices) are better at that given time, therefore a needed optimizing period could be a 7-day period. When making yearly budgeting and long-term investment analysis the total optimizing period may be from one year to e.g. 20 years. Considering the size of the TES, it may be justifiable to split the long optimizing period into monthly optimizing periods. Another optimizing period could therefore be a 4-week period (28 days). These two periods are chosen in the comparison of the UC methods.

3.2.1 Comparison the UC methods on the first 28 days of September

In Table 6 the NHPC during the first 28 days in September is calculated to EUR 17,008 using the MILP solver UC method. As mentioned earlier this is the optimal NHPC, which is possible as the generic DE plant is complex but yet so simplified that a MILP method can deliver optimal UCs. The NHPC of EUR 17,168 for the same period using the advanced analytic UC method is shown in Table 5. It shows that the NHPC when using the advanced analytic UC method is approximately 1% worse than the optimal NHPC (Table 6).

Net Heat Production Cost (NHPC) from 01-09-2016 00:00 to 29-09-2016 00:00							
(All amounts in EUR)							
Operating Expenditures							
Purchase of electricity HP1	238.0	MWh_e				5 681	
Purchase of electricity HP2	253.2	MWh_e				6 071	
Variable operation costs of HP1	833.3	MWh_{heat}	at	2.0	=	1 667	
Variable operation costs of HP2	886.6	MWh_{heat}	at	2.0	=	1 773	
Fuel costs	863.2	GJ	at	5.6	=	4 834	
CO2 quotas	48.9	ton CO_2	at	8.0	=	391	
Variable operation costs of CHP1	42.0	MWh_e	at	5.4	=	227	
Variable operation costs of CHP2	63.0	MWh_e	at	5.4	=	340	
Variable operation costs of boilers	1.2	MWh_{heat}	at	1.1	=	1	
Start costs of CHP1	4	starts	at	30.0	=	120	
Start costs of CHP2	6	starts	at	30.0	=	180	
Start costs of HP1	32	starts	at	10.0	=	320	
Start costs of HP2	36	starts	at	10.0	=	360	
Total Operating Expenditures							**21 965**
Revenues							
Sale of electricity CHP1	42.0	MWh_e				2 007	
Sale of electricity CHP2	63.0	MWh_e				2 949	
Total Revenues							**4 957**
Net Heat Production Cost							**17 008**

Table 6: The NHPC at the DE plant during the first 28 days in September calculated by means of the MILP solver UC method.

Furthermore, noticeably is that the CHP production in the optimal solution results in, if using MILP, a significantly higher production than the CHP production calculated when using the advanced UC priority list method shown in Table 5. The reason for this deviation of the CHP production, even if the NHPCs are practically the same, is to be understood looking at the specific NHPC as shown in Figure 9. At a spot price of approximately 40 EUR/MWh_e the cost of producing 1 MWh_{heat} at CHPs and HPs is the same. Shifting the production from HP to CHP in hours with spot prices around 40 EUR/MWh_e does not change NHPC significantly. That is also shown in Figure 11 showing the optimal UC during the same 7 days as shown in Figure 10. E.g. both CHPs are started 27th of September in the optimal UC but only one CHP is started in the UC calculated using the advanced analytic UC method.

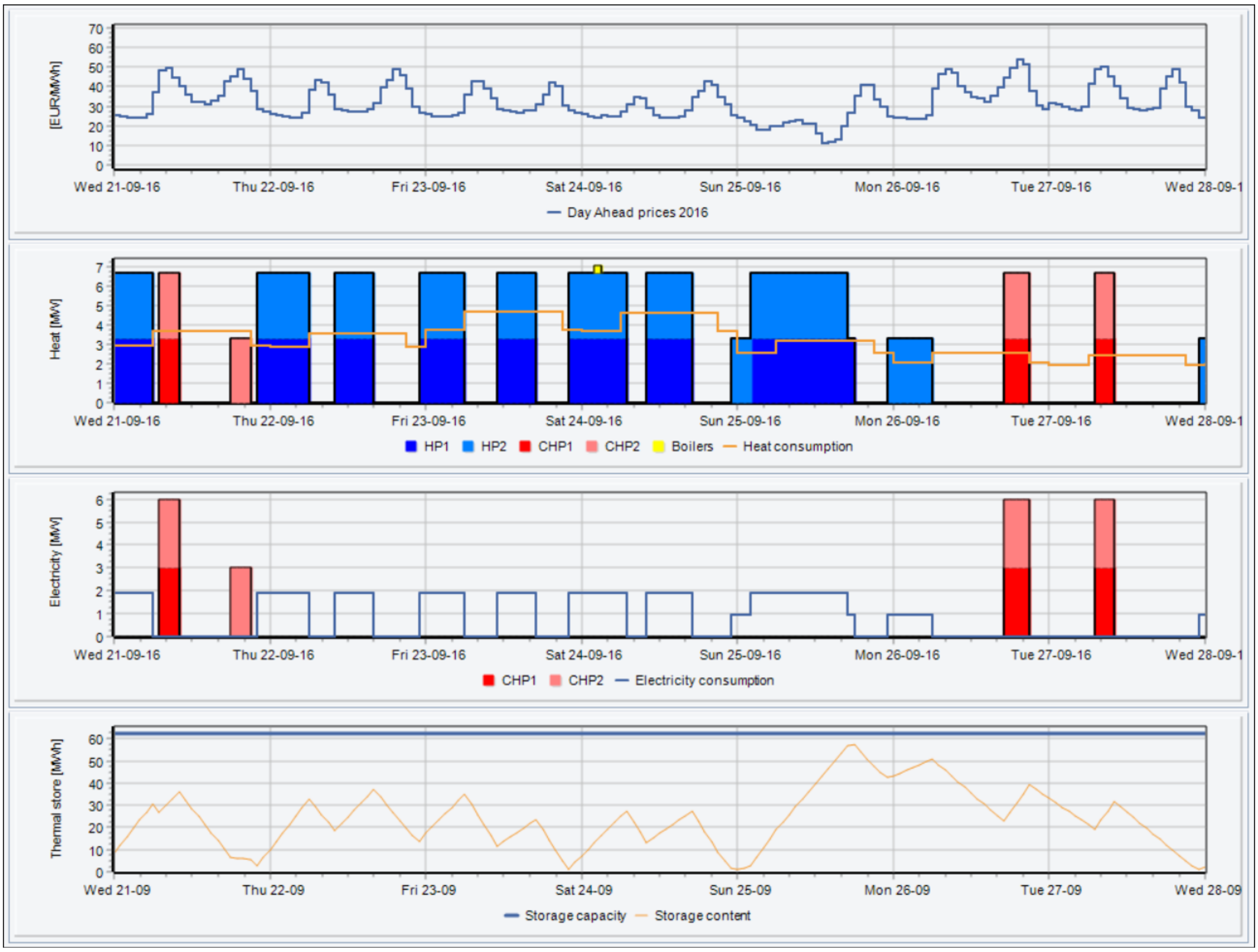


Figure 11: The optimal UC at the DE plant for 7 days in September using the solver-based UC method.

The next step in the test is to calculate the NHPC using the simple analytic UC method as described in Section 3.1.2. Looking at the specific NHPCs in Figure 9 it is obvious that boilers should have the lowest priority, but it depends on the spot price level during the 28-day period whether the CHPs or the HPs should have the highest priority.

With the CHPs having the highest priority, the simple analytic UC method gives a NHPC of EUR 40,118, whereas using the HPs having the highest priority, the NHPC is EUR 19,887. Therefore, comparison will be made using HPs with the highest priority in the simple analytic UC method. The NHPC calculated for the 28-day period with the simple analytic UC method is shown in Table 7. It shows that the high priority HP1 produces close to all the needed heat and the number of starts is extremely low.

Net Heat Production Cost from 01-09-2016 00:00 to 29-09-2016 00:00

(All amounts in EUR)

Operating Expenditures							
Purchase of electricity HP1	524.6	MWh_e				16 138	
Purchase of electricity HP2	0.0	MWh_e				0	
Variable operation costs of HP1	1836.5	MWh_{heat}	at	2.0	=	3 673	
Variable operation costs of HP2	0.0	MWh_{heat}	at	2.0	=	0	
Fuel costs	4.1	GJ	at	5.6	=	23	
CO2 quotas	0.2	ton CO_2	at	8.0	=	2	
Variable operation costs of CHP1	0.0	MWh_e	at	5.4	=	0	
Variable operation costs of CHP2	0.0	MWh_e	at	5.4	=	0	
Variable operation costs of boilers	1.2	MWh_{heat}	at	1.1	=	1	
Start costs of CHP1	0	starts	at	30.0	=	0	
Start costs of CHP2	0	starts	at	30.0	=	0	
Start costs of HP1	5	starts	at	10.0	=	50	
Start costs of HP2	0	starts	at	10.0	=	0	
Total Operating Expenditures							**19 887**
Revenues							
Sale of electricity CHP1	0.0	MWh_e				0	
Sale of electricity CHP2	0.0	MWh_e				0	
Total Revenues							**0**
Net Heat Production Cost							**19 887**

Table 7: The NHPC at the DE plant during the first 28 days in September calculated using the simple analytic UC method.

Figure 12 shows the UC calculated with the simple analytic UC method for the same 7 days as in Figure 11 during the 28-day period. The large TES makes it possible to have few starts of HP1 - even if it is not allowed to operate with partial load.

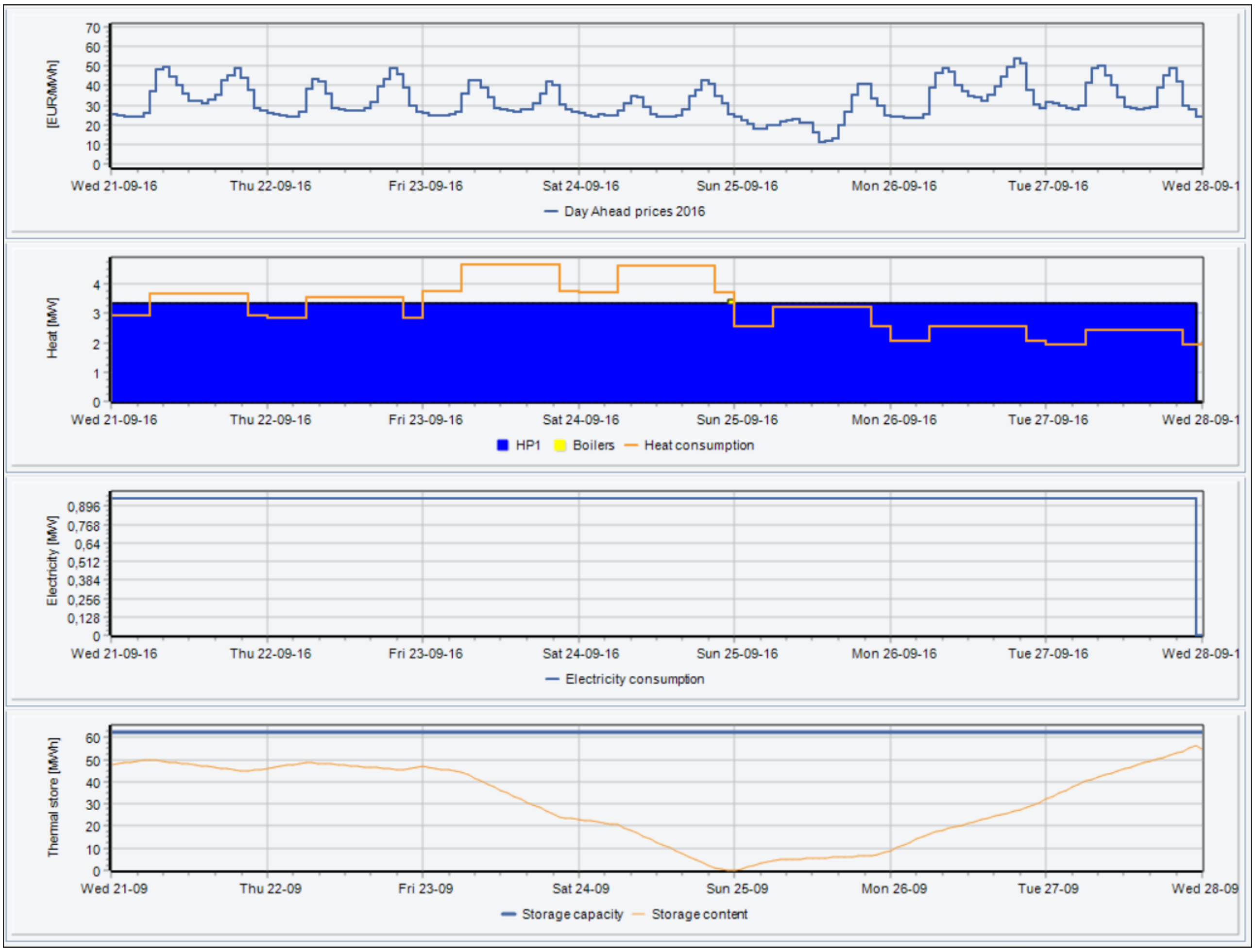


Figure 12: The UC at the DE plant during 7 days in September using the simple analytic UC method.

In Table 8 is compared the three different UC methods. It is seen that the UC calculated with the advanced analytic UC method gives a NHPC which is less than 1% worse than the optimal NHPC calculated by the MILP solver UC method. On the other hand, the UC made by the simple analytic UC method is approximately 17% worse. Furthermore, the sale of electricity is 16% larger and the purchase of electricity is 3% smaller in the optimal UC compared to the UC calculated by the advanced analytic UC method.

	Optimal UC	Advanced UC	Simple UC
Net Heat Production Cost [EUR]	**17 008**	**17 169**	**19 887**
Heat production:			
CHPs [MWh_{heat}]	116.7	100.0	0
HPs [MWh_{heat}]	1 719.8	1 733.2	1 836.5
Boilers [MWh_{heat}]	1.2	4.5	1.2
Number of starts of CHPs	10	8	0
Number of starts of HPs	68	60	5
Purchase of electricity [EUR]	11 751	12 078	16 138
Sale of electricity [EUR]	4 957	4 260	0

Table 8: Comparing the UCs at the DE plant during the first 28 days in September using three different UC methods.

3.2.2 Comparison the UC methods on the first 7 days of September

The same test of the three UC methods, as described in the previous section, is conducted during the first 7 days of September. The short optimizing period is more relevant when making daily operation planning. In Table 9 is shown a comparison parallel to the comparison in Table 8. Similar results are seen when using the UC calculated with the advanced analytic UC method resulting in a NHPC 0.8% worse than the NHPC using the optimal UC, whereas the UC using the simple analytic UC method is approximate 15% worse.

	Optimal UC	Advanced UC	Simple UC
Net Heat Production Cost [EUR]	**4 214**	**4 248**	**4 853**
Heat production:			
CHPs [MWh_{heat}]	26.7	23.3	0
HPs [MWh_{heat}]	416.6	416.6	440.0
Boilers [MWh_{heat}]	0.0	2.0	2
Number of starts of CHPs	1	1	0
Number of starts of HPs	19	15	2
Purchase of electricity [EUR]	2 912	2 974	3 909
Sale of electricity [EUR]	1 070	936	0

Table 9: Comparing the UCs at the DE plant during the first 7 days in September calculated using three different UC methods.

3.2.3 Testing with minimum operation and stop periods

A further test has been made, in which an extra constraint has been introduced. The minimum length of operation periods and minimum length of stop periods for HPs and CHP are set to three hours. The results of this test are shown in Table 10 and Table 11, where similar results are seen as in the 28 days calculations, that the advanced analytic UC method results in a NHPC 0.8% worse than the optimal NHPC, whereas the UC when using the simple analytic UC method is approximately 15% worse.

	Optimal UC	Advanced UC	Simple UC
Net Heat Production Cost [EUR]	**4 214**	**4 248**	**19 887**
Heat production:			
CHPs [MWh_{heat}]	26.7	23.3	0
HPs [MWh_{heat}]	416.6	416.6	1 836.5
Boilers [MWh_{heat}]	0.0	2.0	1.2
Number of starts of CHPs	1	1	0
Number of starts of HPs	19	15	5
Purchase of electricity [EUR]	2 912	2 974	16 138
Sale of electricity [EUR]	1 069	936	0

Table 10: Comparing the UCs at the DE plant during the first 7 days in September calculated using three different UC methods, with the extra constraint that minimum length of operation periods and minimum length of stop periods for HPs and CHP are set to three hours.

It is to be noticed that these extra constraints only reduce NHPC of the optimal UC. The fact that the NHPC is not changed in the advanced UC is amongst others due to the number of production periods are lower with the advanced UC than with the optimal UC.

	Optimal UC	Advanced UC	Simple UC
Net Heat Production Cost [EUR]	**17 039**	**17 169**	**20 169**
Heat production:			
CHPs [MWh_{heat}]	113.3	100.0	0
HPs [MWh_{heat}]	1719 .8	1733 .2	1 833 .1
Boilers [MWh_{heat}]	4 .5	4 .5	4 .5
Number of starts of CHPs	9	8	0
Number of starts of HPs	67	60	6
Purchase of electricity [EUR]	11 756	12 078	16 342
Sale of electricity [EUR]	4 799	4 260	0

Table 11: Comparing the UCs at the DE plant during the first 28 days in September calculated using three different UC methods, with the extra constraint that minimum length of operation periods and minimum length of stop periods for HPs and CHP are set to three hours.

In this section is demonstrated that the NHPC of the presented advanced analytic UC method is with-in 1% of the NHPC of the optimal UC at a generic complex DE plant. It is chosen to simplify the plant, in order for a MILP method to be able to deliver the optimal UC for optimizing periods of respectively 7 days and 28 days. These two periods are typical needed optimizing periods when planning daily operation or making yearly budgeting and long-term investment analysis at DE plants.

4. A method for analysing coordinated investments in production and storage capacity

Investments in large production capacity compared to the instantaneous heat demand at a DE plant needs new methods to be analysed, simply because the feasibility of an investment will be closely dependent on a simultaneous investment in a large TES. The large TES enables e.g. that a large CHP capacity can be fully used producing electricity in hours with high prices in the Day-ahead market, while the surplus heat production is stored in the TES until needed later. Similarly, the large TES enables e.g. that a large HP capacity can be fully used producing heat in hours with low prices in the Day-ahead market, while the surplus heat production is stored in the TES until needed later.

As part of this thesis work a method for analysing coordinated investments in production and storage capacity has been developed.

The description in this section is based on the appended article I. *A method for assessing support schemes promoting flexibility at district energy plants* and the submitted manuscript III. *Support schemes for the radically changing role of District Energy CHPs through the transition to a renewable energy system.* Much of the text in this chapter is copied verbatim from these articles, while many of the more general aspects in the papers are left out here.

The developed investment method consists of an Excel spreadsheet that through Visual Basic for Application (VBA) coding iteratively calls an energy system analysis tool, which for each size of CHPs, HPs and TES, calculates an optimized operation of the production units in a user-given time horizon (planning period). Calculated cash flows are returned to the spreadsheet for each combination, allowing the Net Present Value (NPV) to be calculated. Through iteration, the optimal size of CHPs, HPs and energy stores are thus identified by optimizing the Net Present Value (NPV).

4.1 Choosing an appropriate energy system analysis tool

The energy system analysis tool used in the investment analysis must be able to calculate an optimized operation of user-given production units in each hour of the planning period. This temporal resolution is required by amongst others hourly market prices. The planning period considered is typically 20 years.

Secondly, the tool must be able to assess the business economic consequences for the plant owner. Thirdly, it is a requirement for a tool to be used, that it allows calls from e.g. a spreadsheet, where DE plant design characteristics may be changed.

Sameti and Fariborz have made a comprehensive review of optimization approaches and tools to be used [114]. They conclude that while Mixed Integer Linear Programming (MILP) is the most widely used approach for optimization of DE systems, most models suffer from very long computational time when large networks are considered. Allegrini et al. [115] concludes in their review of tools for simulation of DE systems that there are still many important challenges to be overcome if simulation tools are to provide the benefits on the urban level that they have delivered at the building scale. Olsthoorn et al. focus on storage techniques and renewable energy sources when comparing different tools and methods for modelling district energy plants [116]. Lyden et al. [117] makes a modelling tool selection process for planning of community scale energy systems including storage and demand side management. They conclude that COMPOSE, DER-CAM, energyPRO, EnergyPLAN, MERIT and MARKAL/TIMES are the six tools that meets all essential capabilities. Further to be mentioned is TRNSYS [118] meeting the above mentioned requirements. It is amongst these tools chosen to select energyPRO [34]. In energyPRO the time step may be 1 hour or less thus allowing a calculation of the hourly cash flow. It uses indexes for describing e.g. the development of demands for heating and cooling and the development in prices over the years, which implies that the operation of the production units between the years may change e.g. due to changed economic conditions.

energyPRO is based on analytical programming based on pre-defined methods for finding optimal operation – either through marginal production costs of units or through user-defined priorities. Productions are placed over one-year time horizons based on full foresight of e.g. spot market prices. As a starting point, energyPRO creates a matrix formed by the number of production units times the number of time steps (e.g. 1 h) in the planning period. Each of the cells in this matrix contains a calculated priority number indicating in which order productions are prioritised in the planning period. The priority number for e.g. a CHP in a certain time step could be the cost of producing 1 MWh heat reduced with the value of the associated produced electricity. Thus, if a project has three production units and the simulation is hourly made using one-hour time steps over a one-year period, the matrix would contain 3*8760 priority numbers. energyPRO assigns these hourly productions in a non-chronological way, starting with the production unit in the time step, that has the lowest priority number (highest priority) in the matrix taking into account the restrictions in the energy stores and transmission lines. After having tested if this production is possible, energyPRO continues to the production unit in the time step with the second lowest priority number in the matrix and tests whether this production is possible. This non-chronological way of assigning production has the consequence that each new production before being accepted has to be carefully checked to ensure that it does not disturb already planned productions.
The analyses in this paper are based on a perfect prognosis for electricity market prices when calculating the priority numbers in the matrix. energyPRO thus has perfect foresight and can optimise against known future electricity prices. This analytical method is described more thoroughly by Østergaard et al. [23].

Furthermore, an important reason for using energyPRO, is it is widely used by consultants to analyse investments in DE plants [101]. That brings the method for assessing support schemes close to how investment decisions are made. Furthermore, energyPRO is widely used for research, e.g. Sorknæs et al. have applied energyPRO to study the treatment of uncertainties in the daily operation of combined heat and power plants [102]. Østergaard et al. used energyPRO to optimize the sizing of booster heat pumps and central heat pumps in district heating [23] and to assess the economy of such systems [103]. Fragaki et al. applied energyPRO to study the economic sizing of a gas engine and a thermal store for CHP plants in the UK [104,105]. Streckienė et al. studied the feasibility of

CHP-plants with thermal stores in the German Day-ahead market [106] and Østergaard studied heat and biogas stores' impacts on RES integration [107].

4.2 Choosing the optimal investment

There are different economic criteria used for choosing an optimal investment, amongst others Simple Pay Back time, Internal Rate of Return, NPV, or a combination of more criteria. Here is used the NPV of the additional cash flow at the plant in each month in the planning period, caused by the investment in new units.

As an example, when considering investment in CHPs and TES at a boiler-based DE plant, the payments relating to these additional units include amongst others:

- sale of electricity,
- support paid through the chosen support scheme,
- extra purchase of fuel, because a CHP uses more fuel than boilers to produce the same amount of heat,
- extra use of CO_2 quotas,
- fixed and variable costs of the CHPs,
- reduced variable costs of the boiler and
- the investments in the components.

An optimal solution found by optimizing the NPV may result in identifying too large CHPs and TES compared to what in fact will be established. Smaller sizes may be chosen to save investment cost, but the identified sizes still indicate what CHPs and TES will be established.

For a certain DE plant and a certain level of support the optimal size of the new production units and TES are determined in a two-dimensional matrix-calculation as illustrated in Table 12. Here a CHP capacity of 4.4 MW_e and a TES capacity of 480 m^3 is identified as the combination with the highest NPV. The path to this optimum goes through iterative calls of energyPRO starting with zero CHP and zero TES. First, the size of CHP is increased until the NPV starts to decrease. Keeping this CPH size fixed, the TES is increased until NPV starts to decrease. Then again, the size of the CHP is increased keeping the size of the TES fixed. This procedure continues, until no improved NPV is found.

At a capacity of 3.8 MW_e, the optimization procedure will start increasing the TES until a size of 420 m^3 is reached. Then CHP capacity is increased while keeping the size of the TES fixed. The size of the CHPs then ends at 4.4 MW_e. Then again, the size of the TES is increased keeping the size of the CHPs fixed, which ends the optimization at a CHP capacity of 4.4 MW_e and a TES of 480 m^3 since no further NPV improvement is possible.

In the method, it is possible to choose the precision of the found optimal solution, e.g. by choosing the size of steps when increasing the sizes of the new production units and TES, and it is possible to choose a minimum improvement in NPV for accepting an increase in the sizes of the components.

Total CHP capacity [MW_e]	TES [m^3]									
	0	**60**	**120**	**180**	**240**	**300**	**360**	**420**	**480**	**540**
3.00	2.515	2.585	2.627	2.651	2.662	2.665	2.663	2.659	2.654	2.648
3.20	2.563	2.642	2.692	2.722	2.738	2.744	2.744	2.742	2.739	2.735
3.40	2.598	2.686	2.742	2.777	2.797	2.805	2.807	2.806	2.803	2.800
3.60	2.623	2.715	2.775	2.815	2.838	2.849	2.853	2.853	2.851	2.848
3.80	2.632	2.727	2.794	2.838	2.865	2.878	2.884	2.885	2.884	2.882
4.00	2.627	2.727	2.797	2.846	2.878	2.895	2.902	2.905	2.905	2.903
4.20	2.605	2.713	2.790	2.845	2.883	2.903	2.913	2.917	2.918	2.917
4.40	2.570	2.687	2.772	2.834	2.876	2.902	2.915	2.922	2.924	2.924
4.60	2.522	2.648	2.742	2.809	2.857	2.887	2.904	2.913	2.916	2.917
4.80	2.461	2.596	2.698	2.772	2.823	2.857	2.877	2.888	2.893	2.896

Table 12: An example of the path to an optimal solution, shown in a section of a decision matrix of Net Present Values in Mio. EUR of investment in CHP and TES at a DE plant.

Using this heuristic to find an optimum offers a much faster calculation, compared to calculating all possible combinations of CHP´s and TES capacities. Shown in Figure 13 is an example of the investment analysis method being used in the appended article III. Support schemes for the radically changing role of District Energy CHPs through the transition to a renewable energy system [98].

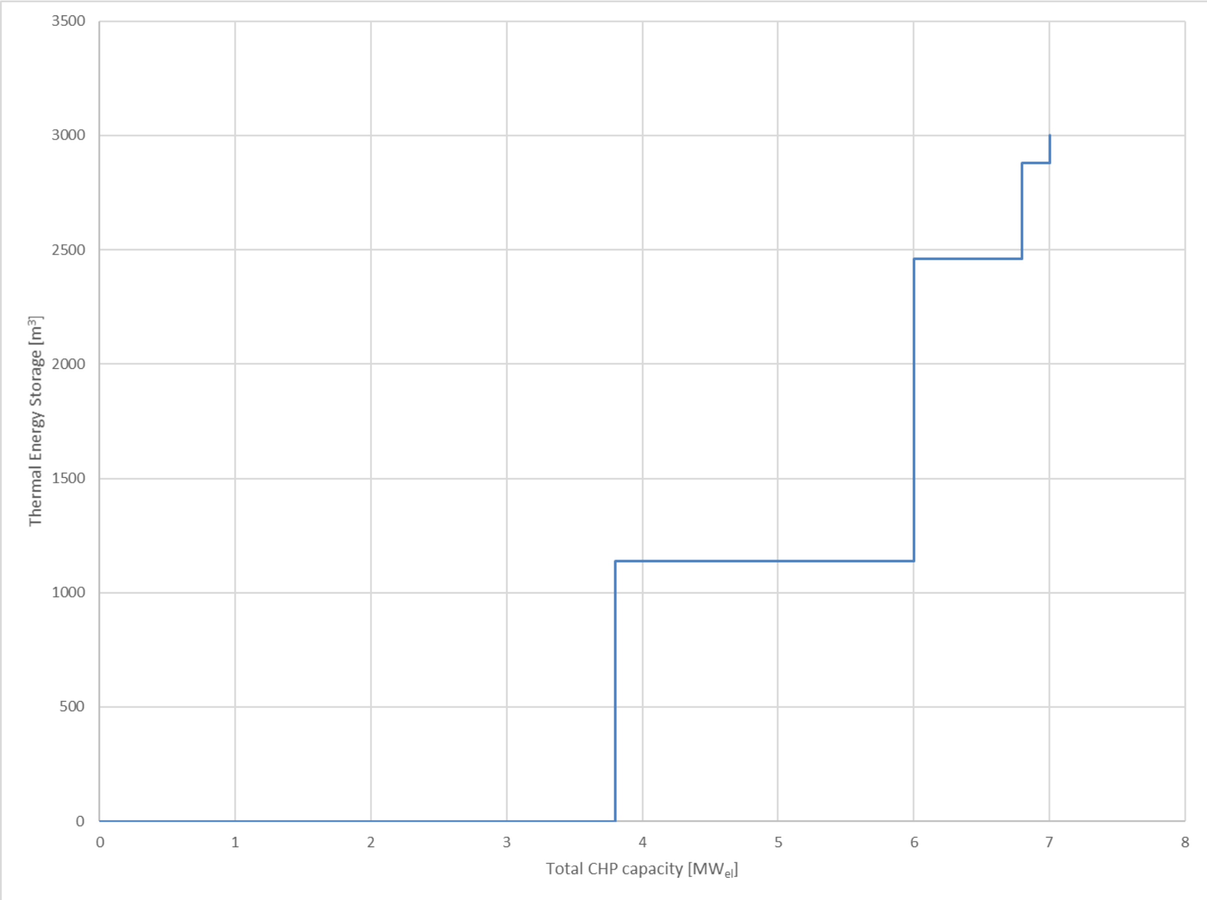


Figure 13: For a certain DE plant the optimal size of the CHPs and TES are determined in a two-dimensional matrix-calculation. In this figure is shown the path to the optimal NPV of the size of the CHPs and TES at the Triple tariff, as described in [98].

5. A method for comparing the effect of support schemes at DE plants

DE plants have a role to play but will often require support to fulfil this. For financial reasons, this should be minimised while supporting adequate quantities. In this section is presented a method for comparing support schemes promoting CHPs, HPs and TES at DE plants.

The description in this section is based on the appended article I. *A method for assessing support schemes promoting flexibility at district energy plants* and the submitted manuscript III. *Support schemes for the radically changing role of District Energy CHPs through the transition to a renewable energy system.* Much of the text in this chapter is copied verbatim from these articles, while many of the more general aspects in the papers are left out here.

Different schemes have been applied in different places at different times for supporting DE CHPs, amongst others Feed-in premiums, Feed-in tariffs, Quota obligations, Tax exemptions, Tenders and Investment aids. Each of these support scheme types can be designed differently and even combined with the aim of meeting the requirements for the support schemes.

Two of the most widely used support scheme types are the Feed-in premium types and the Feed-in tariff types, made as a triple tariff. These are introduced and reviewed in the next two sections. Hereafter in the following sections an example of the use of the method by comparing these two.

5.1 The Premium support scheme

The premium is paid on top of hourly wholesale electricity prices and is made as a flat-rate price supplement paid to CHPs for each produced MWh_e, independent of which hour the electricity is produced. There is not assumed any cap on the premium paid, that is to say that even if the wholesale electricity price in a certain is high, the DE plant will still receive the premium.

5.2 The Triple tariff support scheme

The procedure of determining the Triple tariff includes both a procedure for determining the time periods and the prices of the Peak, High and Low tariff. The procedure is similar to the used procedure in the Danish Triple tariff as described in the Danish legislation [33], and includes a procedure for calculating the savings at central power plants and the saved grid losses and grid investments. The procedure assumes a strict Phase 1 situation, where the DE CHPs is assumed to displace fossil fuelled condensing mode power plants.

5.2.1 The three load periods

When used in a certain country the first step in the procedure is to decide the periods of the Peak, High and Low tariff, which is made by analysing the demand for electricity and grouping it into three load situations with a weekly cycle, eventually being split into winter and summer load situations. The periods used in the analysis reported in this article are the ones used in Denmark in 2015; these are shown in Table 13. The tariffs paid for electricity delivered from local CHP plants is equal within each of the tariff periods but dependent on the voltage level at which the CHP production is delivered.

	Low tariff periods	High tariff periods in working days	Peak tariff periods in working days
Winter (October-March)	21.00– 06.00 All holidays All weekends	06.00 – 08.00 12.00 – 17.00 19.00 – 21.00	08.00 – 12.00 17.00 – 19.00
Summer (April-September)	21.00– 06.00 All holidays All weekends	06.00 – 08.00 12.00 – 21.00	08.00 – 12.00

Table 13: The separation of the year into low, high and peak tariff periods as applied in the Danish Triple tariff in 2015 [33].

5.2.2 The procedure for calculating savings at central power plants

The total saved costs at central power plants, SC_i, for each reduced production of 1 MWh_e depends if the reduced production takes place in Low, High or Peak tariff periods and illustrated in Equation (2), where the index i designates the tariff period.

$$SC_i = \frac{GP*3.6}{\eta} + V_{Plant} + \frac{(YC_{plant}*I_{plant}+YF_{Plant})*D_i}{FLH_i} \qquad (1)$$

The saved cost is split into saved fuel, variable operation and maintenance cost, investment cost and fixed operation and maintenance cost. Saved fuel and variable operation and maintenance cost is straightforward related to reduced amount of produced electricity, but how a reduction in produced electricity translates into reductions in investment costs and reductions in fixed operation and maintenance cost is of a more probabilistic nature. In this Triple tariff procedure is applied a method where a part of the reduced need for investment and reduced fixed operation and maintenance cost is assigned to reduced produced electricity in Peak and High tariff periods respectively, but no part is assigned to Low tariff periods.

In equation (1) η is the net electrical efficiency at central power plants, GP the natural gas price is in EUR/GJ and the V_{Plant} variable operation and maintenance cost is in EUR/MWh_e, YC_{plant} is the yearly capital cost factor of investment, I_{plant} is the investment cost in EUR/MW_e, YF_{Plant} is the yearly fixed operation and maintenance cost in EUR/MW_e, D_i are distribution keys between Low, High and Peak tariff periods for investment and yearly fixed costs and FLH_i is full load hours of electricity demand calculated for each of the Low, High or Peak tariff periods as the electricity demand in the period divided by the peak demand for electricity of the year.
The yearly capital cost factor - YC_{plant} - is calculated as an annuity (Equation (2)) dependent on the discount rate (r) and the life-time of the investment (L). The yearly capital cost factor thus determines the share of an investment that is attributed to each year of operation.

$$YC = \frac{r}{1-(1+r)^{-L}} \qquad (2)$$

5.2.3 The procedure for calculating saved grid losses and grid investments

Delivering electricity to the 60 kV-grid is assumed to replace an amount of electricity to be delivered from the central power plants. However, delivering one unit of electricity in the 60 kV-grid replaces more than one unit from the central power plant as grid losses in the 150 and 400 kV grids are avoided. Also, as grid losses increase with the transmission system load, the value of delivery of electricity to the 60 kV-grid is higher, the higher the load situation is. Furthermore, delivering electricity in the 60 kV-grid is assumed to reduce the need for investments in the 150 kV-grid, and again, this reduced investment is larger at higher load situations, using the same arguments that led to equation (1). Thus, the compensation for electricity delivered in the 60 kV-grid, $P@60_i$, depends on the fact if the production happens in Low, High or Peak tariff periods and is given by equation (3). $NL150_i$ is the load and tariff period-dependent net Loss percentage in the combined 150 & 400 kV-grid, YC_{grid} is the yearly capital cost factor of investment in electrical grids and I_{150} is investment cost in the 150 kV-grid in EUR/MW$_e$.

$$P@60_i = SC_i/(1 - NL150_i) + YC_{grid} * I_{150} * D_i/FLH_i \tag{3}$$

Similar conditions apply when delivering electricity to the 10 kV-grid or to the 0.4 kV-grid. Thus, the paid compensations of electricity delivered to the 10 kV-grid, $P@10_i$, and to the 0.4 kV-grid, $P@0.4_i$, are given by Equations (4) and (5).

$$P@10_i = P@60_i/(1 - NL60_i) + YC_{grid} * I_{60} * D_i/FLH_i \tag{4}$$

$$P@0.4_i = P@10_i/(1 - NL10_i) + YC_{grid} * I_{10} * D_i/FLH_i \tag{5}$$

Here $NL60_i$ and $NL10_i$ are the net Loss percentages in the 60 and 10 kV-grids respectively, and I_{60} and I_{10} are investment cost in the 60 and 10 kV-grids respectively in EUR/MW$_e$.

Finally, supplying electricity to the 0.4 kV-grid directly at the site of consumption furthermore is assumed to reduce grid losses and reduce the need for investment in the 0.4 kV grid. Thus, the compensation to be paid for electricity delivered to the consumer, $P@consumer_i$, is given by Equation (6)

$$P@consumer_i = P@0.4_i/(1 - NL0.4_i) + YC_{grid} * I_{0.4} * D_i/FLH_i, \tag{6}$$

where $NL0.4_i$ is the net Loss percentage in the 0.4 kV-grid and I_{150} is investment cost in the 0.4 kV-grid in EUR/MW$_e$.

Notice that the procedure for calculating paid prices is cumulative – i.e. supplying at 0.4 kV also provides saving in 10, 60, 150 and 400 kV grids so therefore the rationality of the equations is that prices at higher voltage levels always influence prices at lower voltage levels.

5.2.4 The data used to calculate the Triple tariff prices

The Triple tariff prices are calculated with the power plant and grid data shown in Table 14, and the tariff-period dependent data shown in Table 15. The shown data are equal to the data used in the

Danish Triple tariff at the end of 2015. The used power plant net electrical efficiency used is high but comparable to the efficiency expected in 2020 by Danish Energy Agency [112].

Power plant net electrical efficiency	η	58%	
Power plant, Variable operation and maintenance cost	V_{Plant}	2.54	EUR/MWh_e
Power plant, Yearly fixed operation and maintenance cost	YF_{Plant}	13,597	EUR/MW_e
Real discount rate	r	3%	
Investment cost in power plant	I_{plant}	0.905	$MEUR/MW_e$
Life time of power plant	L_{plant}	25	years
Yearly capital cost factor of investment in power plant	YC_{plant}	0.05743	
Investment cost in the 150 kV-grid	I_{150}	0.286	$MEUR/MW_e$
Investment cost in the 60 kV-grid	I_{60}	0.095	$MEUR/MW_e$
Investment cost in the 10 kV-grid	I_{10}	0.054	$MEUR/MW_e$
Investment cost in the 0.4 kV-grid	$I_{0.4}$	0.054	$MEUR/MW_e$
Life time of electrical grids	L_{grid}	25	years
Yearly capital cost factor of investment in electrical grids	YC_{grid}	0.05743	

Table 14: The power plant and grid data not depending on the tariff periods, used for calculating the Triple tariff.

		Low tariff	High tariff	Peak tariff
Hours per year	H_i	5010	2498	1252
Full load hours of electricity demand	FLH_i	2475	1728	1097
Distribution keys for investment and yearly fixed costs	D_i	0	0.5	0.5
Net Loss percentage in the 150 + 400 kV-grid	$NL150_i$	2.8%	4.2%	4.7%
Net Loss percentage in the 60 kV-grid	$NL60_i$	2.1%	3.2%	3.6%
Net Loss percentage in 10 kV-grid	$NL10_i$	1.4%	2.7%	3.5%
Net Loss percentage in 0.4 kV-grid	$NL0.4_i$	2.8%	5.1%	6.8%

Table 15: The power plant and grid data depending on the tariff periods, used for calculating the Triple tariff.

5.3 The DE plant case

The DE plant case is similar to the case used in [39] and shortly recapitulated in this section. The yearly heat delivered to the district heating grid is 40 GWh of which grid loss and domestic hot water represent 40% and are assumed to be constant and thus also weather independent.

The remaining 60% is the space heating and assumed linearly dependent on ambient temperature. It is assumed that space heating is only required in days with an average temperature below 15 °C. A diurnal variation is assumed, with the delivered heat demand approximately 20% lower during the nocturnal hours compared to hours during daytime, which is based on empirical evidence from Danish DH systems [119]. The resulting heat demand requires an average delivered heat from the plant of 4.6 MW, with a maximum heat delivered from the plant of 11.6 MW and a minimum of 1.6 MW.

As the reference situation for analysing an investment in CHPs and TES, an existing DE plant is assumed to produce the heat on existing heat-only boilers. These boilers are assumed to have an efficiency of 97.1% and variable operation costs of 1.10 EUR/MWh_{heat}, which in the reference situation with the assumed economic conditions described in this section gives a yearly heat production cost of 0.938 M EUR.

Investment and operation costs are assumed to be strictly proportional to the sizes of the CHPs – thus it is not important in how many units the CHPs are split into. However, it is chosen to split the CHP capacity between two CHP units, as shown in Figure 8, which is in good accordance with how DE plants are designed, as exemplified at online presentations at [119]. Splitting the CHP capacity in more units also reduces the need to include partial load operation characteristics.

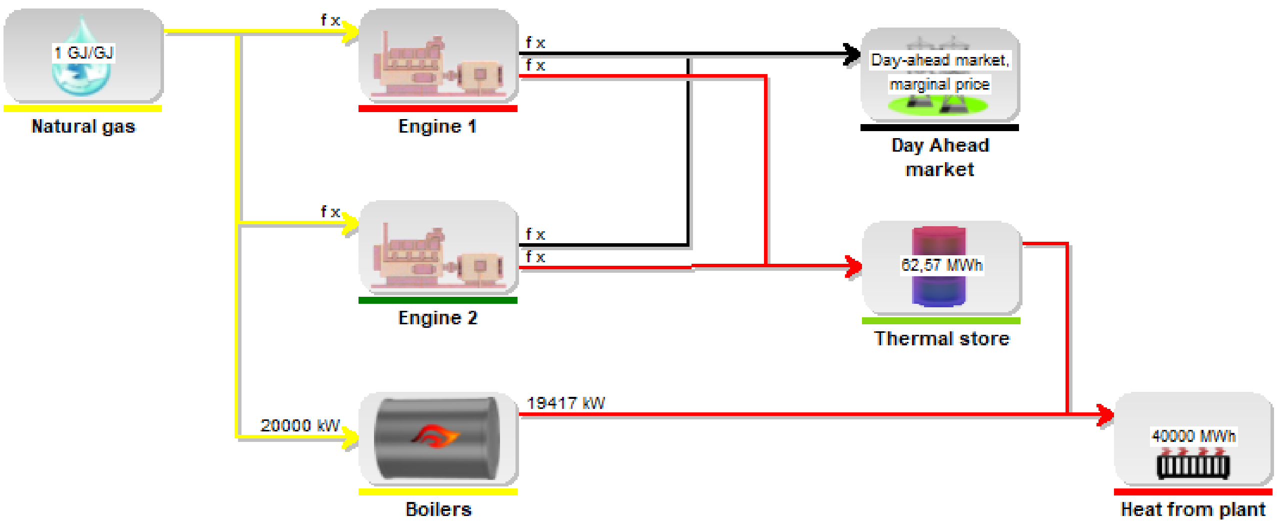


Figure 14: The generic DE plant used in the test of the two support schemes, consisting of existing boilers and the new units - 2 CHPs and a TES.

The remaining 60% is the space heating and assumed linearly dependent on ambient temperature. It is assumed that space heating is only required in days with an average temperature below 15 °C. A diurnal variation is assumed, with the delivered heat demand approximately 20% lower during the noctural hours compared to hours during daytime, which is based on empirical evidence from Danish DH systems [119]. The resulting heat demand requires an average delivered heat from the plant of 4.6 MW, with a maximum heat delivered from the plant of 11.6 MW and a minimum of 1.6 MW.

As the reference situation for analysing an investment in CHPs and TES, an existing DE plant is assumed to produce the heat on existing heat-only boilers. These boilers are assumed to have an efficiency of 97.1% and variable operation costs of 1.10 EUR/MWh_{heat}, which in the reference situation with the assumed economic conditions described in this section gives a yearly heat production cost of 0.938 M EUR.

Investment and operation costs are assumed to be strictly proportional to the sizes of the CHPs – thus it is not important in how many units the CHPs are split into. However, it is chosen to split the CHP capacity between two CHP units, as shown in Figure 8, which is in good accordance with how DE plants are designed, as exemplified at online presentations at [119]. Splitting the CHP capacity in more units also reduces the need to include partial load operation characteristics.

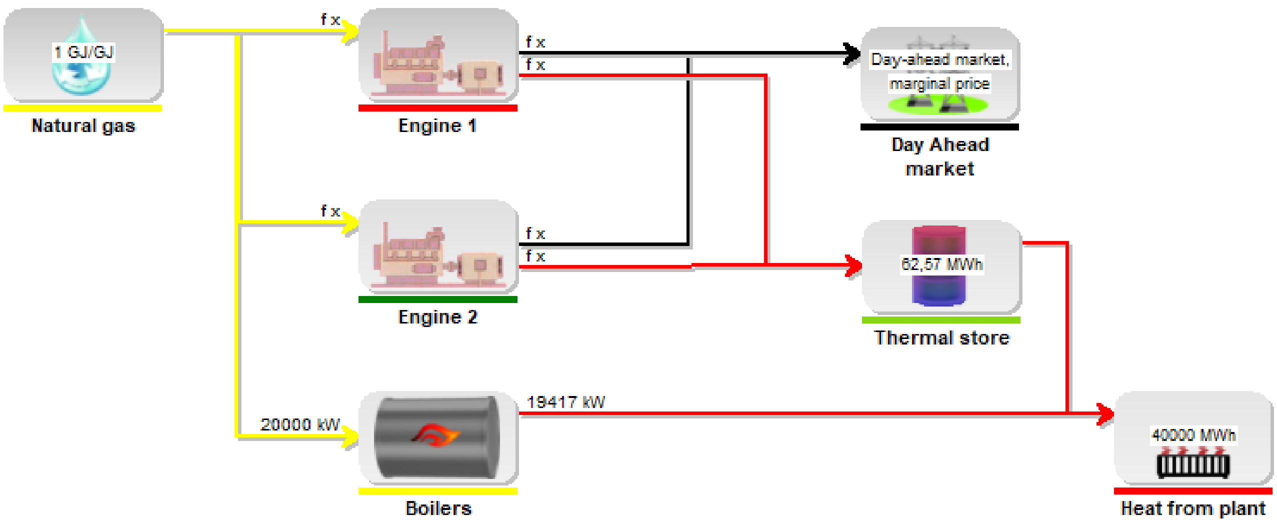


Figure 15: The generic DE plant used in the test of the two support schemes, consisting of existing boilers and the new units - 2 CHPs and a TES.

5.4 Technical and economic assumptions

In this comparison, efficiencies are chosen to be kept constant over time and with no size-dependency. A similar simplification has been made regarding investment and operation costs which are being modelled proportionally to the sizes of both the CHPs and TES. An overview of technical and economic data used in the comparison is shown in Table 16. The data correspond to the data used in [39].

Gas price	5.60	EUR/GJ
CO_2 quota price	8.00	EUR/tonne
Existing boilers		
Heat efficiency	97.1%	
Variable operation costs	1.00	EUR/MWh_{heat}
CHPs		
Electrical efficiency	44.0%	
Heat efficiency	48.9%	
Total efficiency	92.9%	
Fixed operation costs	10000	EUR/MW_e/year
Variable operation costs	5.4	EUR/MWh_e
Investment in CHPs	650000	EUR/MW_e
Non-availability periods per year	16	days
Investment in installation	350000	EUR/MW_e
Thermal storage		
Investment in thermal storage	200	EUR/m^3

Table 16: Technical and economic characteristics (2016-prices) used in the comparison of the two support schemes based on [112]

The cost for society when providing a support scheme is in this analysis set equally to the NPV of the paid support in the planning period of 20 years. The support is calculated for each hour during the planning period and is subsequently summed in an NPV calculation to determine the total support in the planning period.

For the Premium scheme, the cost of the support in a certain hour is calculated simply as the premium multiplied by the electricity produced on the CHPs in that hour.
For the Triple tariff, the support in a certain hour is calculated as the tariff in that hour minus the Day-ahead price in that hour. This difference is then multiplied with the electricity produced on the CHPs in that hour. This interpretation of support is consistent with the way a Triple tariff is often administered. Being paid a Triple tariff often includes that either the transmission system operator or a trader (balancing responsible party) is responsible for selling the produced electricity at the Day-ahead market, thus it is only the discrepancy between the Triple tariff and the Day-ahead price in that hour, that makes up the support, often to be paid by the consumers through a grid tariff. That is also to imply, that if in a certain hour the price in the Day-ahead market is higher than the Triple tariff, the support will be negative in that hour.

In this comparison the Day-ahead prices for all years in the planning period are set as the hourly prices in West Denmark in 2016.

5.5 Results of the comparison of the two support schemes

This section introduces a two-step procedure for comparing support schemes and applies to the case with the given support schemes.

The first step in comparing the two support schemes is to calculate the business economic optimal CHP and TES with the Triple tariff. The result of this calculation is shown in Figure 13 showing an optimal total CHP capacity of 7 MW_e and a TES size of 3000 m^3.
The next step is to determine the support level of the Premium scheme, that results in the same optimal CHP capacity of 7 MW_e. This way of finding the support level of the Premium scheme, that gives the same CHP capacity of 7 MW_e is shown in Figure 16. The support level is found to be 66.67 EUR/MWh_e.

It is illustrated in the figure that a Premium scheme support less than 10 EUR/MWh_e causes no CHP capacity to be installed and from a level of support around 25 EUR/MWh_e the growth in electrical CHP capacity becomes smaller as operation is restricted by a limited heat demand at the DE-plant. The slightly irregular shape of the graph is due to the fact that when identifying the optimal NPV the step value for electrical capacity is set equal to 0.2 MW_e and the step value for TES size is set equal to 60 m^3. These step sizes are chosen to reduce calculation time without compromising the conclusions based on the calculation.

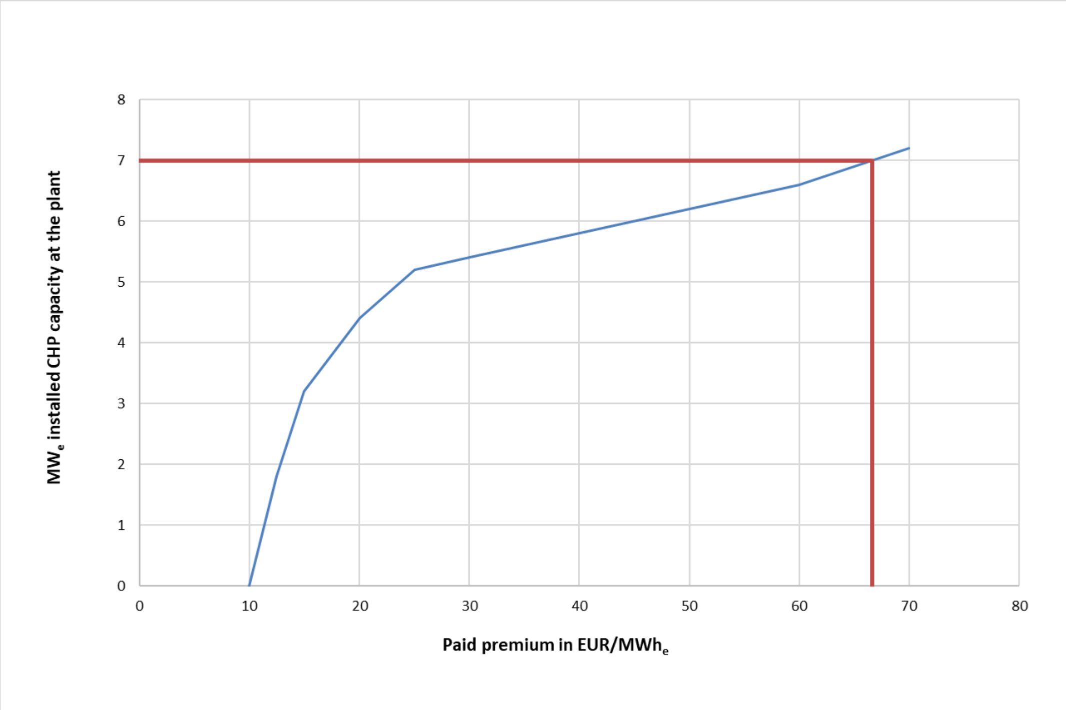


Figure 16: Determining the paid premium giving the total CHP capacity of 7 MW$_e$ being equal to 66.67 EUR/MWh$_e$.

The results are shown in Table 17. It is seen that at this total CHP capacity of 7 MW$_e$ the belonging TES capacity is the double when using the Triple tariff than when using the Premium scheme, which also implies a total investment in CHP and TES capacity that is slightly bigger when using the Triple tariff than when using the Premium scheme. The net present value in a 20-year period (NPV$_{20}$) of the changed cash flow caused by the investment in the CHPs and TES is around 22 M EUR bigger when using the Premium scheme. This is also reflected in the extra NPV$_{20}$ of support to the plant when using the Premium scheme compared to the Triple Tariff Scheme.

This is the most thought-provoking result; that the societal cost is nearly three times bigger for providing a certain CHP capacity when using the Premium scheme than when using the Triple tariff.

	CHP capacity [MW$_e$]	TES size [m^3]	Investment [M EUR]	NPV$_{20}$ of extra cash flow caused by the investment in the CHPs and store [M EUR]	NPV$_{20}$ of paid support [M EUR]	Yearly electricity produc-tion [MWh$_e$]
Triple tariff	7.00	3000	7.60	3.59	12.92	34440
Premium scheme (66.67 EUR/MWh$_e$)	7.00	1520	7.30	25.48	34.05	34345

Table 17: Results of the comparison of the Triple tariff and the Premium scheme both resulting in a CHP capacity of 7 MW$_e$.

6. Discussion

The work done in this PhD study has made the first steps towards the development of next generation generalized energy system simulation tools for district energy, being able to analyse very different alternatives for DE plants providing heating and cooling. In this section is discussed questions that have to be further researched when developing these tools.

6.1 DE plants participating across more of the electricity markets

The developed tools shall be able to simulate DE plants participating across more of both the existing and future electricity markets, to make a proper analysis of the value of large production and storage capacity. This requires flexible tools to be able to do such simulations, because the organization of these markets, when it comes to e.g. gate closures and price settlements may be very different.

As seen in West Denmark, the electricity markets may be split into five markets. The Agency for the Cooperation of Energy Regulators (ACER), an EU agency, is working on creating common balancing markets namely Frequency Containment Reserves, Frequency Restoration Reserves and Replacement Reserves [48]. These balancing markets, as indicated in Figure 17, will together with the two whole-sale markets (Day-ahead market and Intraday market), be the five markets that DE plants often can choose between for potential participation – with variation across different countries.

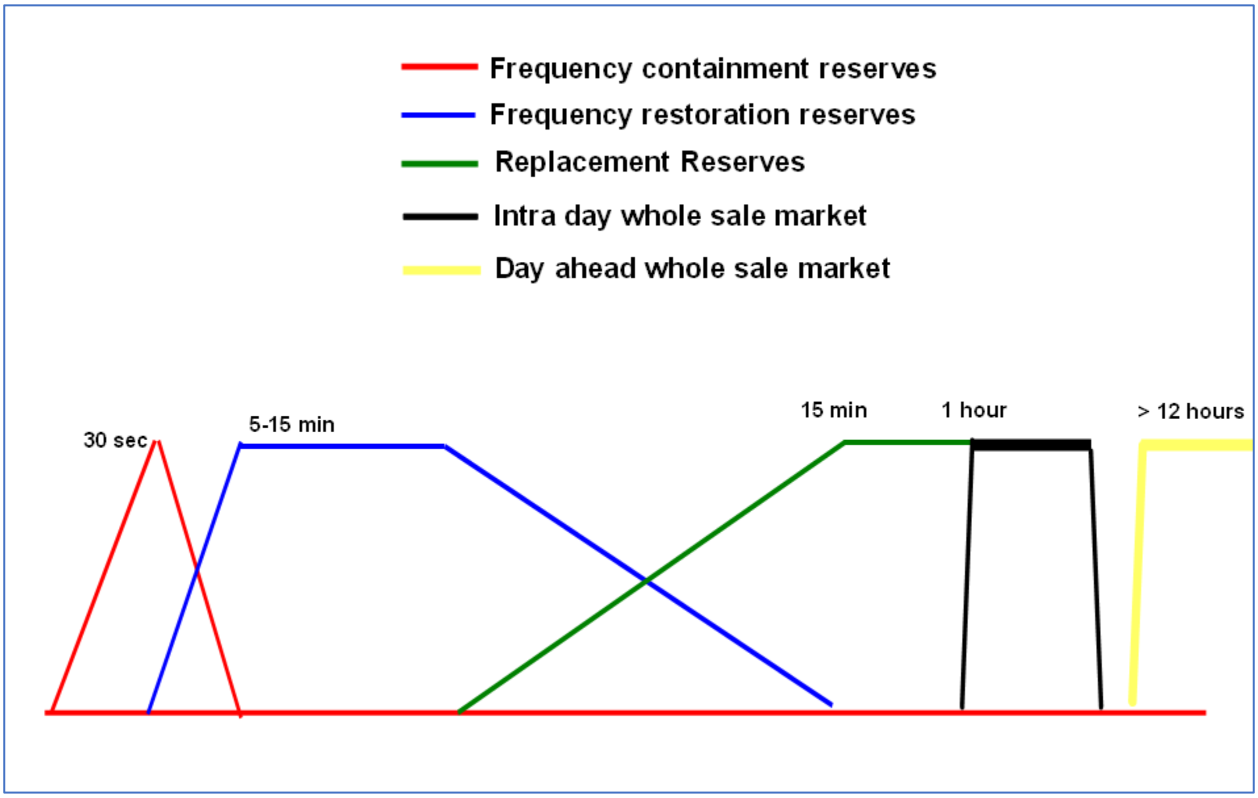


Figure 17: ACER´s [47] general framework for the organization of thee electricity markets.

The complexity of simulating DE plants participating across these markets is shown online at [119] for both the current and historic operation of the West Danish electricity system as well as examples of the current and historic operation of five West Danish DE plants.

As an example, Figure 17 shows the operation of the West Danish electricity system 8th of August. The bottom dark blue area shows the aggregated production of the wind turbines, the yellow shows the production of the PV, the lighter dark blue areas shows the power production at the distributed DE plants and at the top the power production at the central power plants. It is seen that the wind turbines in many hours produce around 10 times more power than the distributed DE plants and the central power plants. The green line shows the prices in the West Danish Day-ahead market, and the blue line (upward regulation) and yellow line (downward regulation) show activation prices in the West Danish Replacement Reserves market (Regulating power market).

What makes 8th of August noteworthy is the high upward regulation prices from 9-11 o´clock, which showed prices around 2000 DKK/MWh_e. Furthermore, what makes 8th of August noteworthy was that it seems that wind turbines from 17-20 o´clock won downward regulation, but as there is not shown yellow prices in these hours, it was probably not in the Replacement Reserves market but probably in the Special regulation market [120], which is a special market operated by the TSO to avoid bottle necks in the grid.

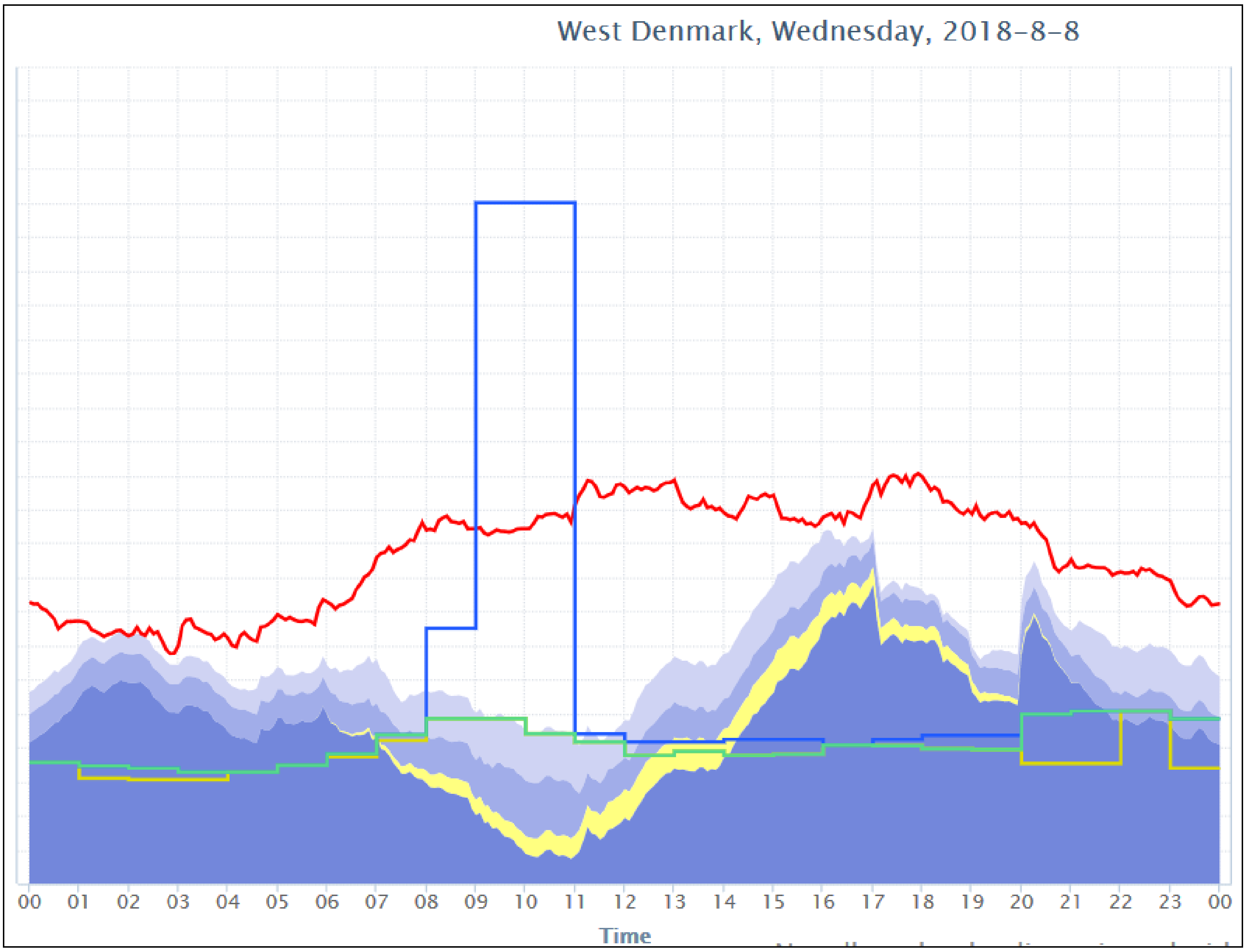


Figure 18: The operation of the West Danish electricity system 8th of August 2018 [119]

It is interesting to observe how the DE plants operated that day. In Figure 19 is shown the operation of Skagen DE plant. It is seen that two of the CHPs were activated (in total 9.4 MW_e and 14.4 MW_{heat}) from 9 to 11 o´clock in the well-paid hours for upward regulation in the Regulating power market. Similarly the electrical boiler was activated from 17 to 20 o´clock winning downward regulation (in total 10 MW_e). This day both the CHPs and the electrical boiler created valuable earnings, that simulation tools have to be able to reproduce.

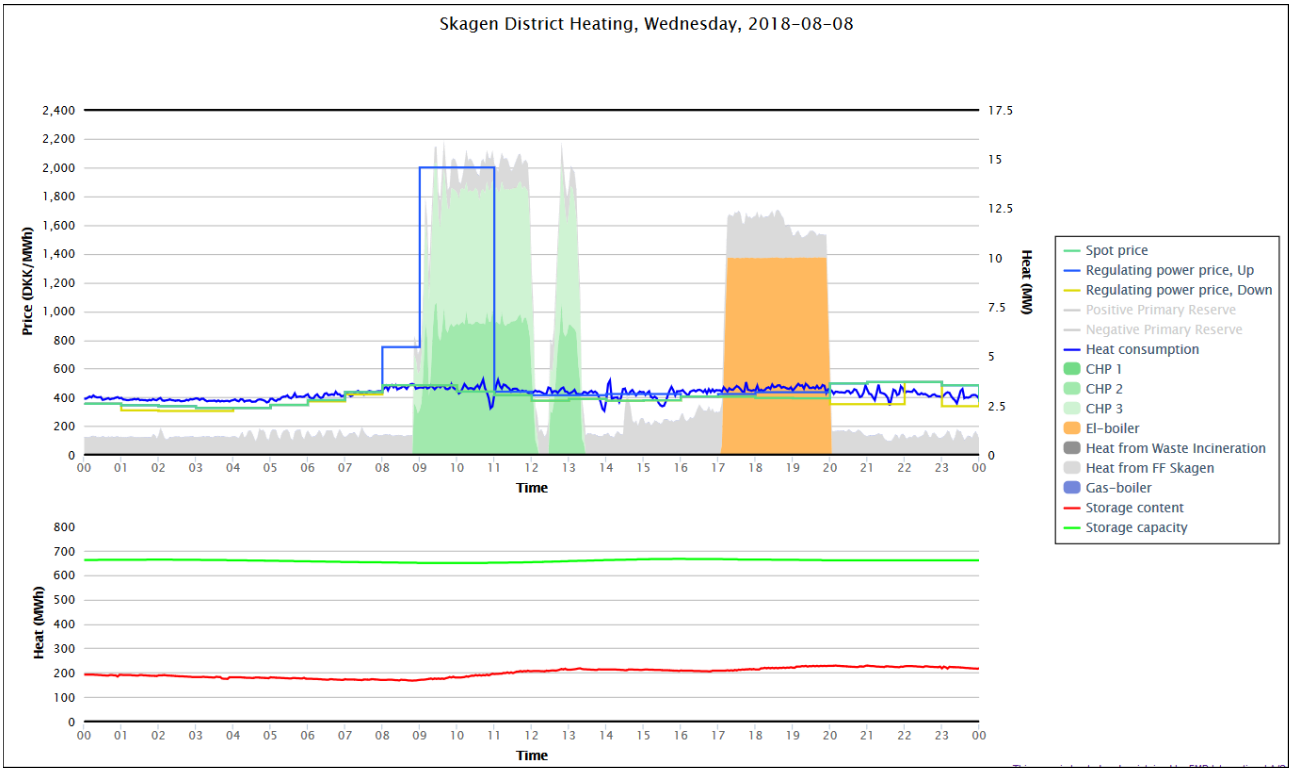


Figure 19: The operation of Skagen DE plant 8th of August 2018 [119]

What makes 8th of August demonstrate is that future research is needed to allow a proper simulation of DE plants participating across more of the electricity markets, when looking into the operation of some of the other DE plants shown online at [119].

As seen in Figure 20 the two CHPs at Hvide Sande were not activated from 9 to 11 (in total 7.4 MW_e and 9.8 MW_{heat}), and as seen in Figure 21 the CHP at Ringkøbing was not activated from 9 to 11 o´clock (in total 8.8 MW_e and 10.3 MW_{heat}).
When it comes to winning down ward regulation from 17 to 20 o´clock only Hvide Sande was activated (in total 6 MW_e and 6 MW_{heat}), but not Ringkøbing (in total 12 MW_e and 12 MW_{heat}).

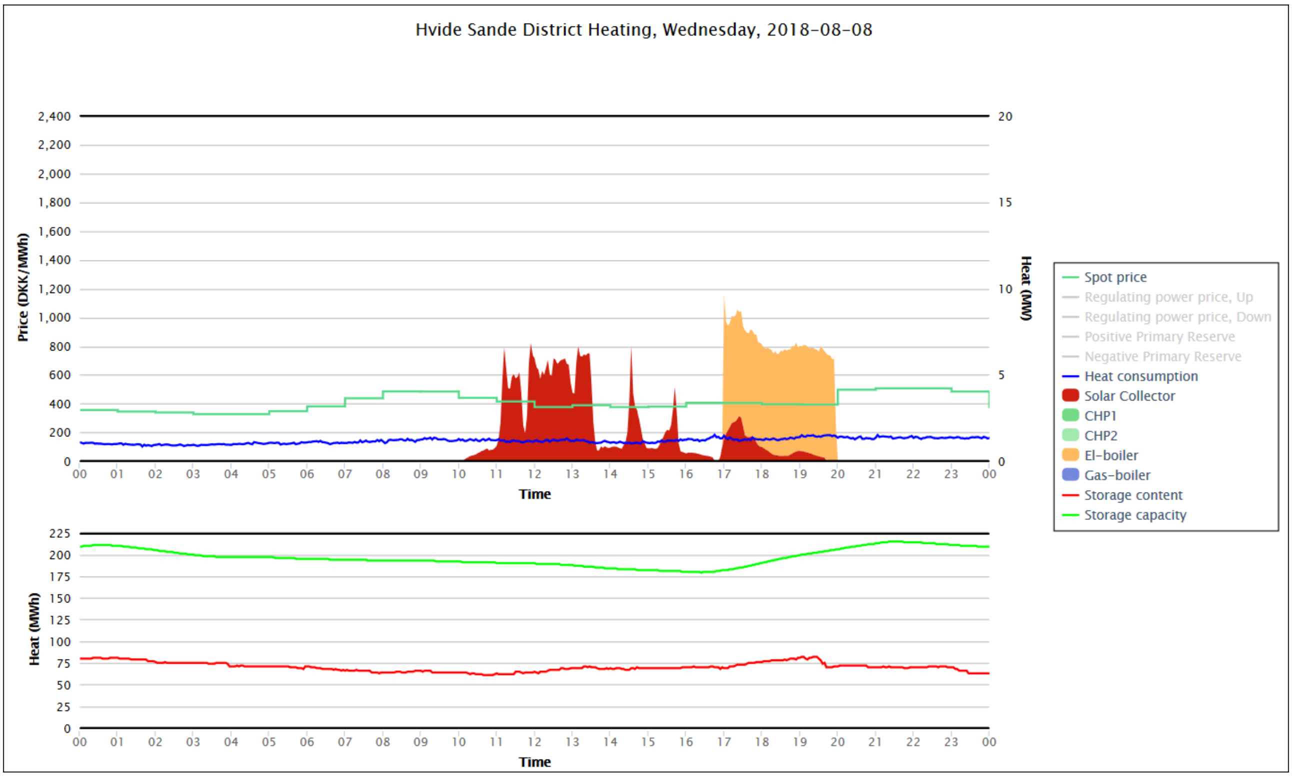


Figure 20: The operation of Hvide Sande DE plant 8th of August 2018 [119]

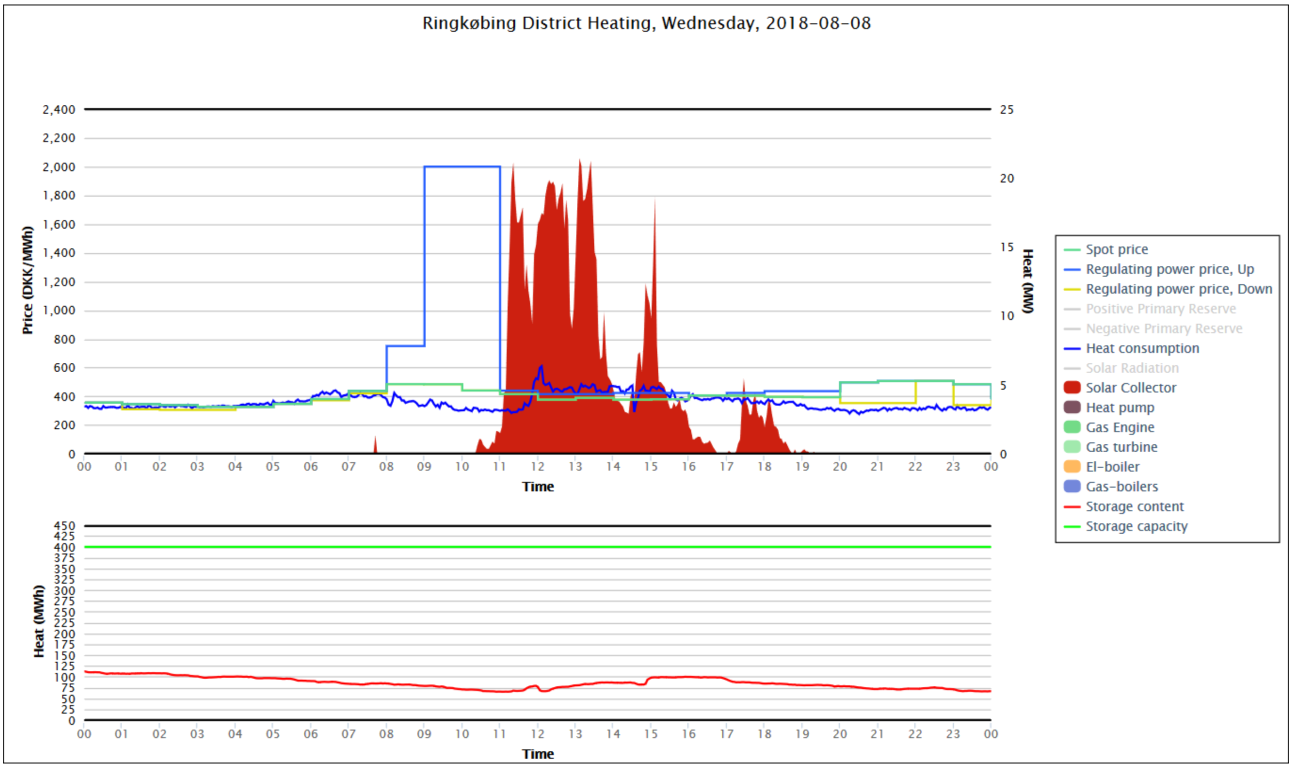


Figure 21: The operation of Ringkøbing DE plant 8th of August 2018 [119]

Another example showing that future research is needed to allow a proper simulation of DE plants participating across more of the electricity markets is seen at Skagen DE plant 16th of December 2018. From 2-6 o´clock the TSO needed downward regulation and the prices in the Regulating power market became negative, making it very attractive for DE plants to win downward regulation. But only the boiler won downward regulation from 2-6 o´clock. It has to be investigated why the CHPs did not stop in these hours.

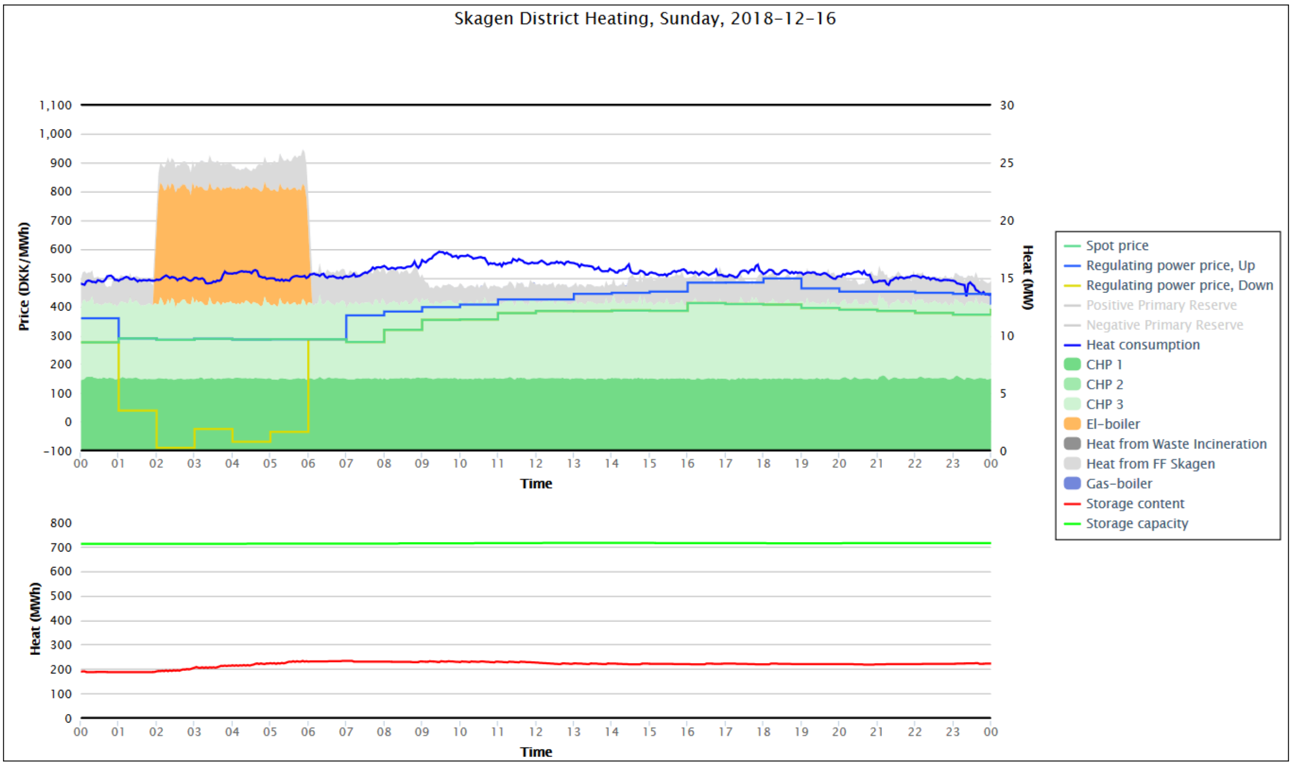


Figure 22: The operation of Skagen DE plant 16th of December 2018 [119]

6.2 More research in complex production units are needed

Development of next generation generalized energy system simulation tools for district energy needs to use sufficiently simplified models for each of the production units at the DE plant, yet using so detailed model for each of the production units that the calculated operations are robust for deciding new investments and daily operation.
Robust models for HPs at DE plants are needed, but e.g. when the heat source is ambient temperature, they might become complicated as illustrated in Figure 23 and Figure 24. As is seen the heat production at the HP are very fluctuating. The manager at Ringkøbing DE plant [121] has informed that it is due to that the heat exchanger has regularly to be defrosted when ambient temperatures are low.

Figure 23: The ambient air heat source for the HP at Ringkøbing DE plant [119].

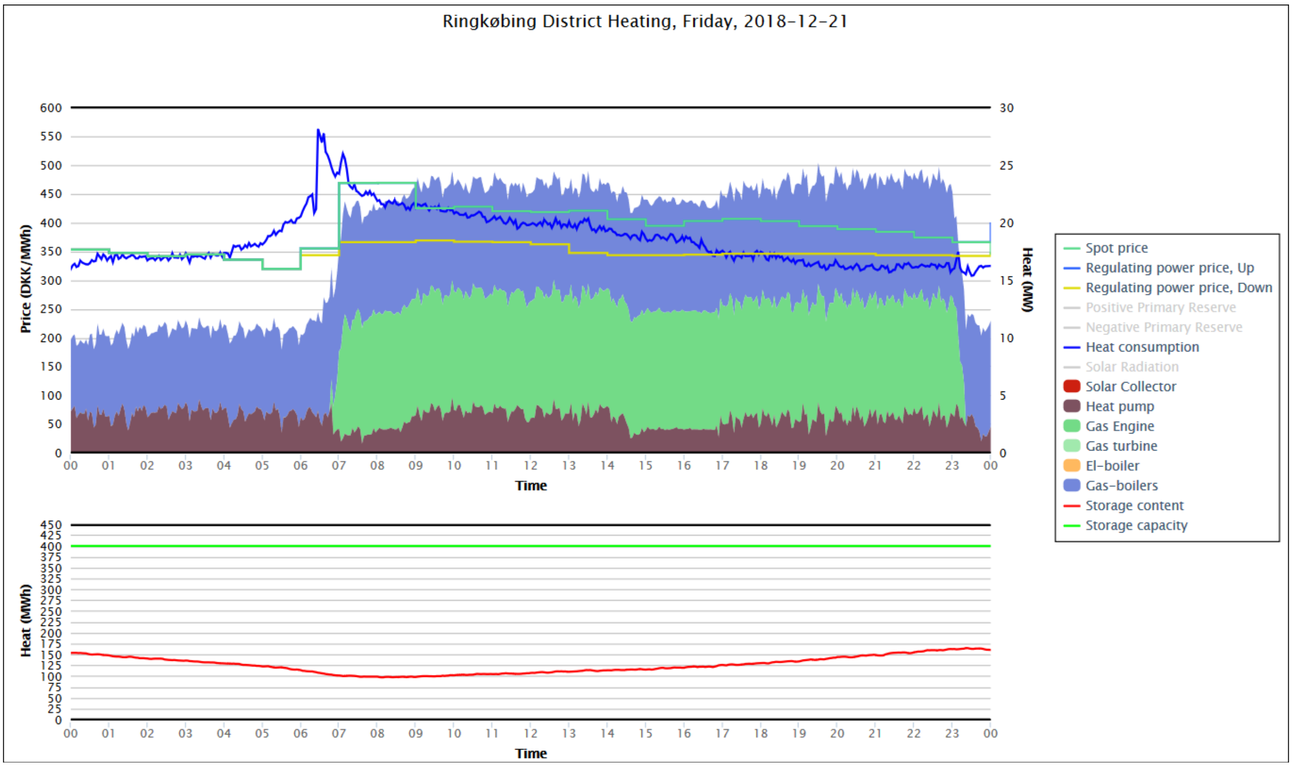


Figure 24: The operation of Ringkøbing DE plant 21th of December 2018 [119]

6.3 More research in unit commitment methods at DE plants are needed

The next steps in the research of the UCs for DE plants could be to making use of and combining the best of analytic and solver-based UC methods, and to compare these methods against the real UCs seen at DE plants. Examples of further research in UC is given in this section.

6.3.1 CHP operated in both condensing mode and extraction mode

Apparently, the UC of a CHP being able to be operated in both condensing mode and extraction mode is not easily made with the advanced analytic UC method presented in Section 3.1.1, because the needed priority numbers become multi-dimensional. In Figure 25 this is illustrated by a two-dimensional model to describe the multitude of operation modes possible, which is illustrated as a feasible operating region of such a CHP plant (operation modes allowed inside the polygon area).

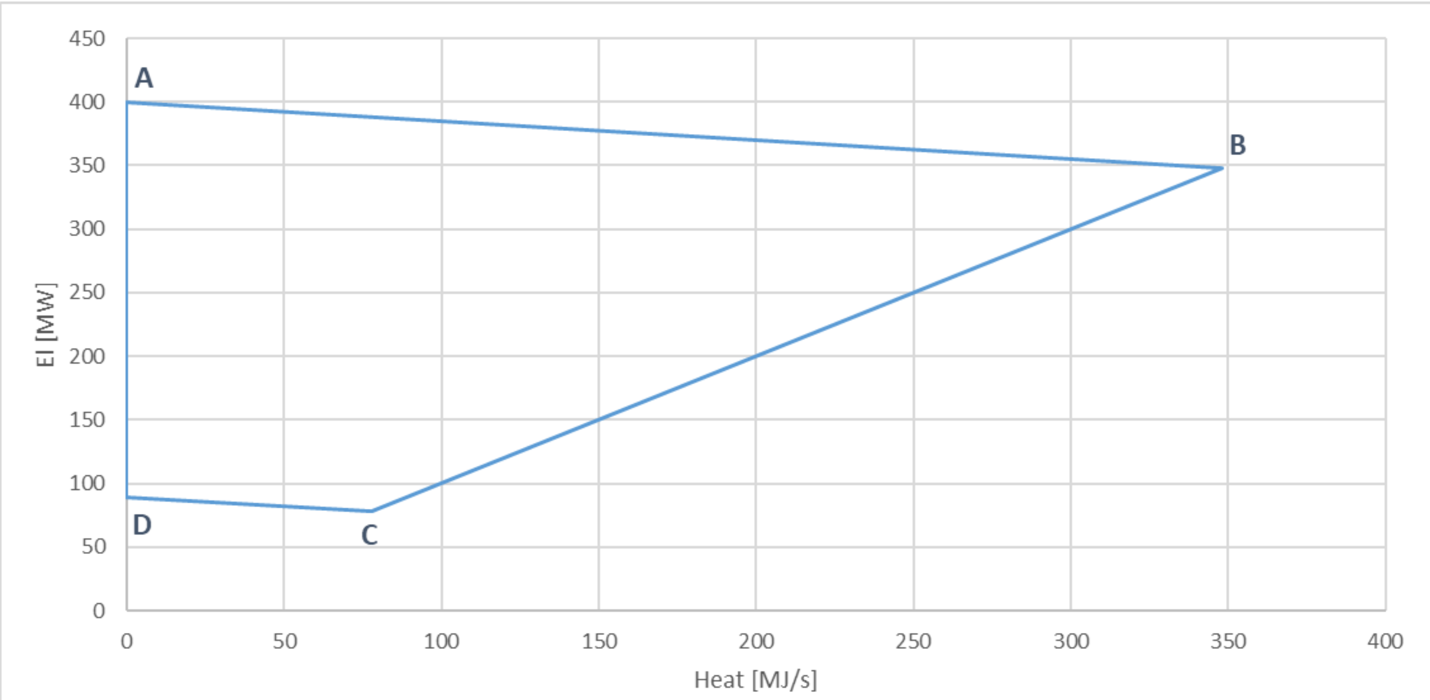


Figure 25: A CHP being able to be operated in both condensing mode and extraction mode inside the polygon area.

However, it is expected to be possible to simplify the modelling of this CHP, without compromising a sufficiently precise energy system analysis. This is done by assuming that all operation happens on the edge of the polygon and that the CHP is modelled as four separate ECUs operated in subsequent operation modes, as shown in Table 18 and in Figure 26.

Operation modes of extraction plant	Fuel consumption [MJ/s]	Heat production [MJ/s]	El. production [MW]	El. Efficiency [%]	Total efficiency [%]
[A] Full Condensing Mode	888,9	0,0	400,0	45,0%	45,0%
[B] Full Backpressure Mode	888,9	348,0	347,8	39,1%	78,3%
[C] Min Backpressure Mode C	198,9	78,0	77,8	39,1%	78,3%
[D] Min Condensing Mode	198,9	0,0	89,5	45,0%	45,0%
Modelled as separate subsequent operation modes					
Min Condensing Mode zero to D	198,9	0,0	89,5	45,0%	45,0%
Min Backpressure Mode D to C	0,0	78,0	-11,7		
Full Backpressure Mode C to B	690,0	270,0	270,0	39,1%	78,3%
Full Condensing Mode D to A	690,0	0,0	322,2	46,7%	46,7%

Table 18: CHP modelled as 4 separate ECUs operated in subsequent operation modes.

Notice that in fact “Min Backpressure Mode D to C” is producing negative electricity and is as such modelled as a heat pump.

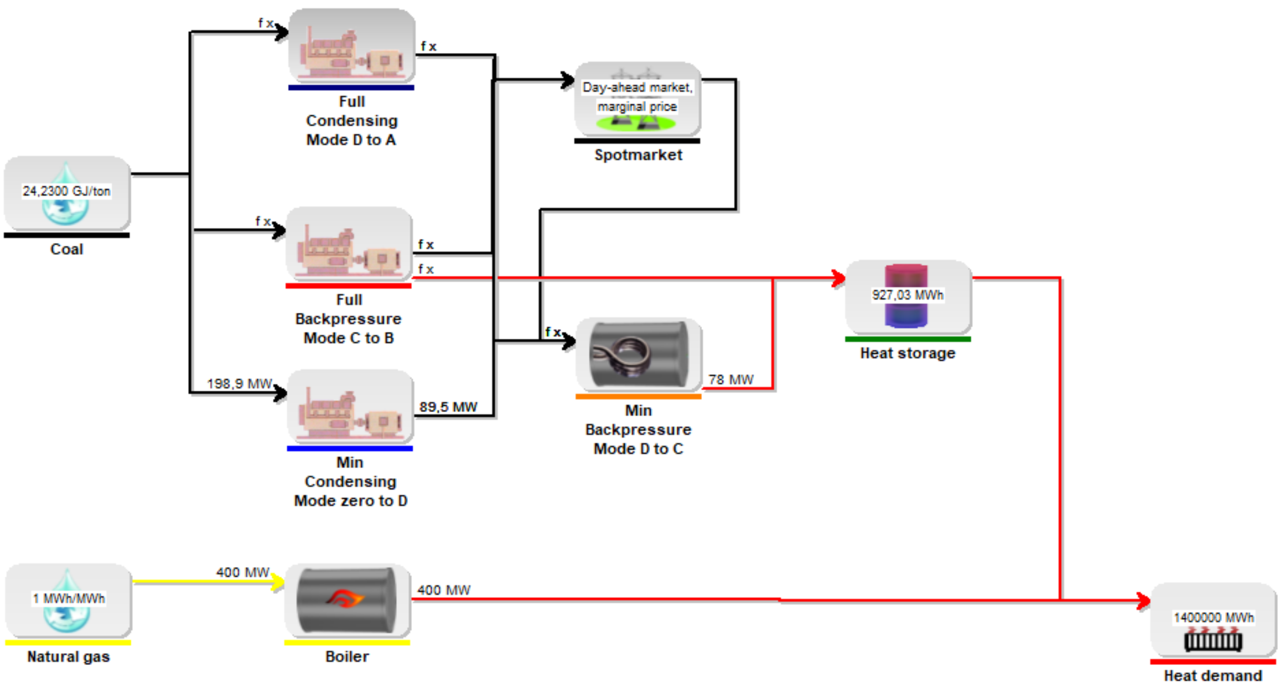


Figure 26: An energy plant equipped with a CHP modelled as four separate ECUs operated in subsequent operation modes and equipped with a gas boiler.

The operation strategy of a usual gas engine CHP is about coproducing heat and electricity in hours with high spot prices. That is not the case with a CHP being able to be operated in both condensing mode and extraction mode. On the contrary it shall in hours with high spot prices stop coproducing heat and electricity and instead produce electricity in condensing mode to allow for the highest electricity production possible.
Assuming an economy of the plant in Figure 26 being described simple by a cost of coal of 600 DKK/ton and an operation and maintenance cost of the CHP of 30 DKK/ton of coal (heat value in

coal of 24.23 GJ/ton) and a production cost on the gas boiler of 500 DKK/MWh$_{heat}$, gives a NHPC as function of spot prices shown in Figure 27 for the separate operation modes.

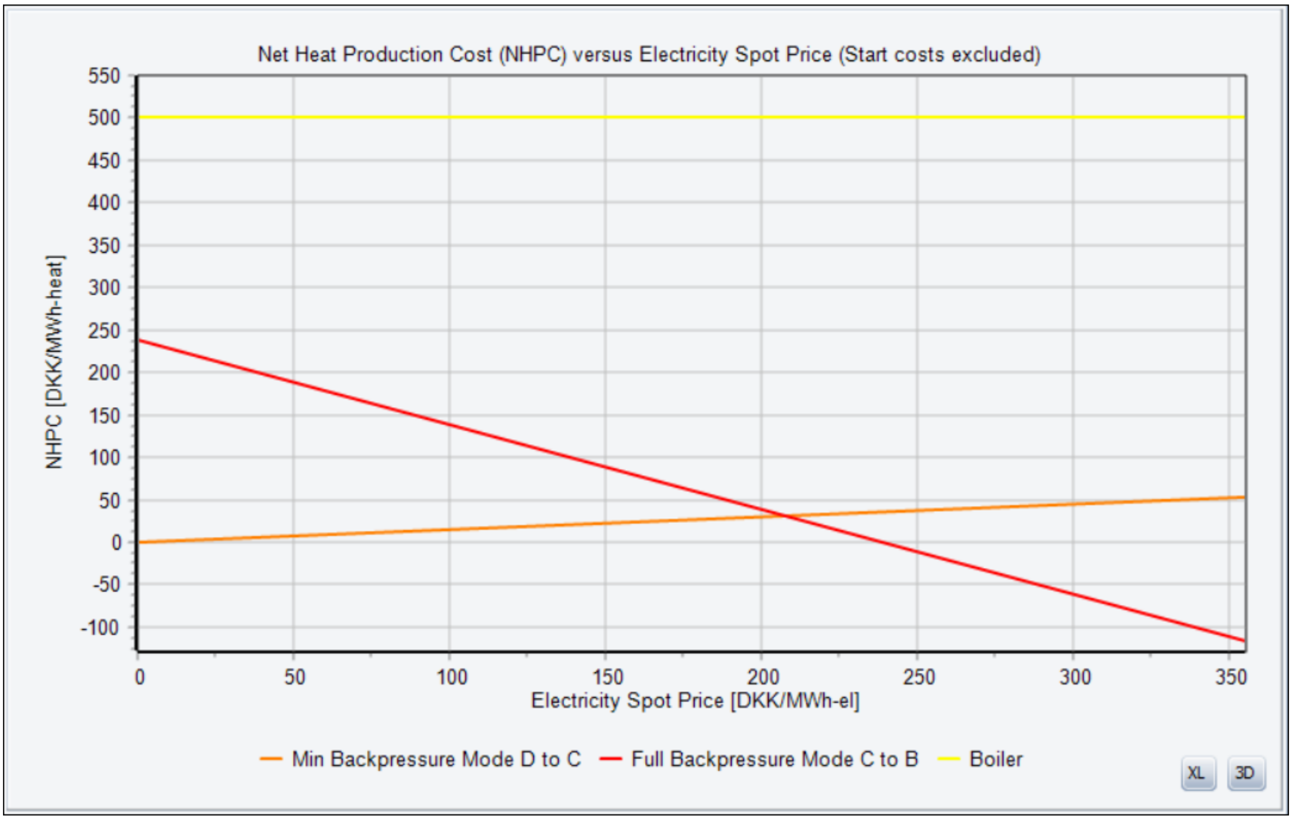


Figure 27: The NHPC of the operation modes shown in Table 18 and showing the NHPC of the gas boiler.

When including in an analytic method that other operation modes are only allowed if "Min Condensing Mode zero to D" is in operation and that operating "Full Backpressure Mode C to B" is only allowed if "Min Backpressure Mode D to C" is operating. This allows that at high spot prices it has low priority to coproduce heat and electricity and primarily produce electricity in condensing mode, simply because the "Min Backpressure Mode D to C" being modelled as a heat pump will have low priority operating at high spot prices, and since "Full Backpressure Mode C to B" is only allowed operating if "Min Backpressure Mode D to C" is operating, this constraint will reduce priority of combined heat and power production on the CHP at high spot prices. An example of such an operation of the CHP described in this section is shown in Figure 28. The upper graph shows the spot prices, the next two graphs show heat and electricity productions, and the bottom graph shows content in the thermal store. It is seen that e.g. at 25th of September 2019, when the spot prices are high, combined heat and power production stops and the CHP is operated in condensing mode, and the thermal store is emptied.

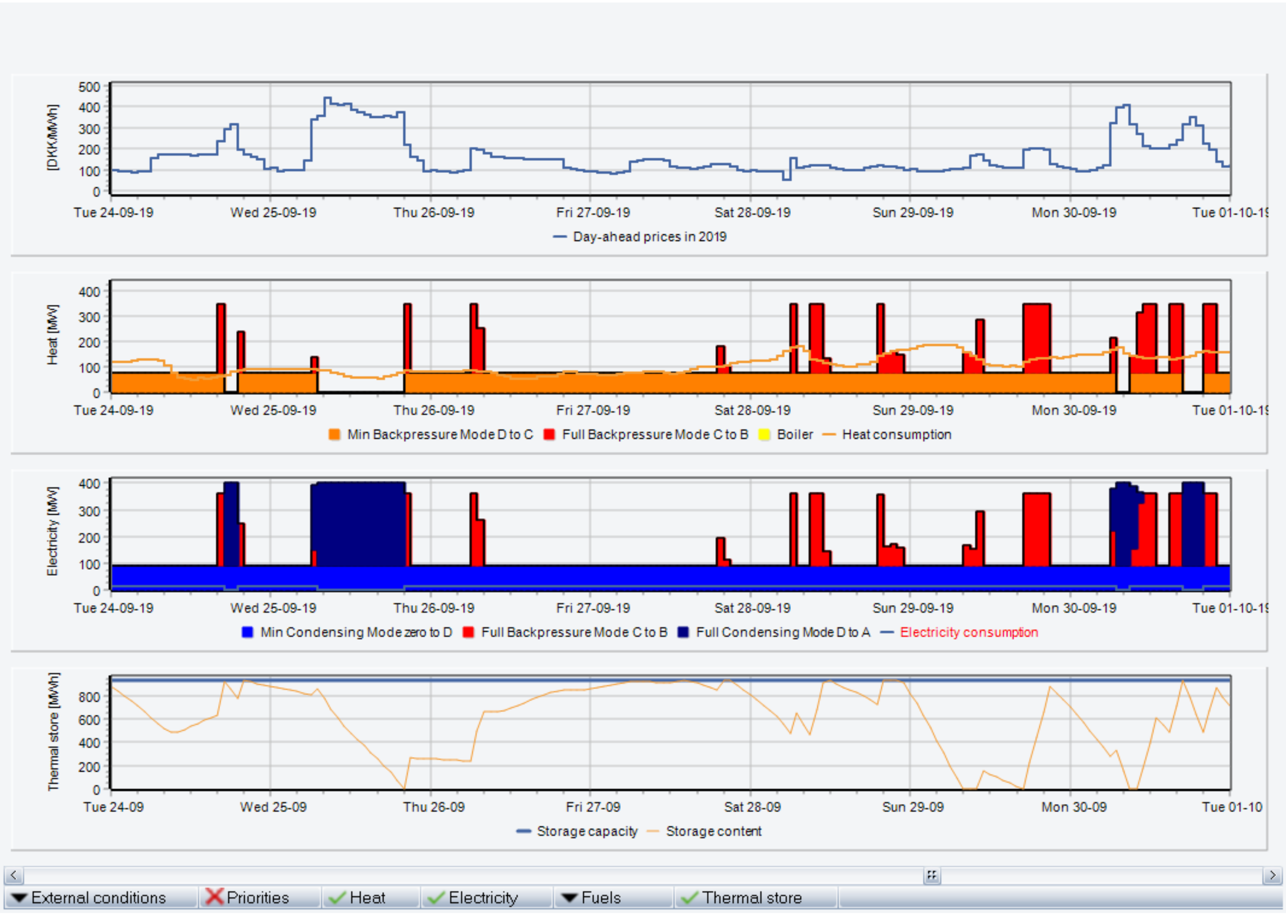


Figure 28: An example of the operation of the CHP described in this section, modelled as 4 separate ECU´s operated in subsequent operation modes.

Using such an analytical method for optimizing UC described in gives the operation in each hour of 2019 shown in Figure 29 (orange points).

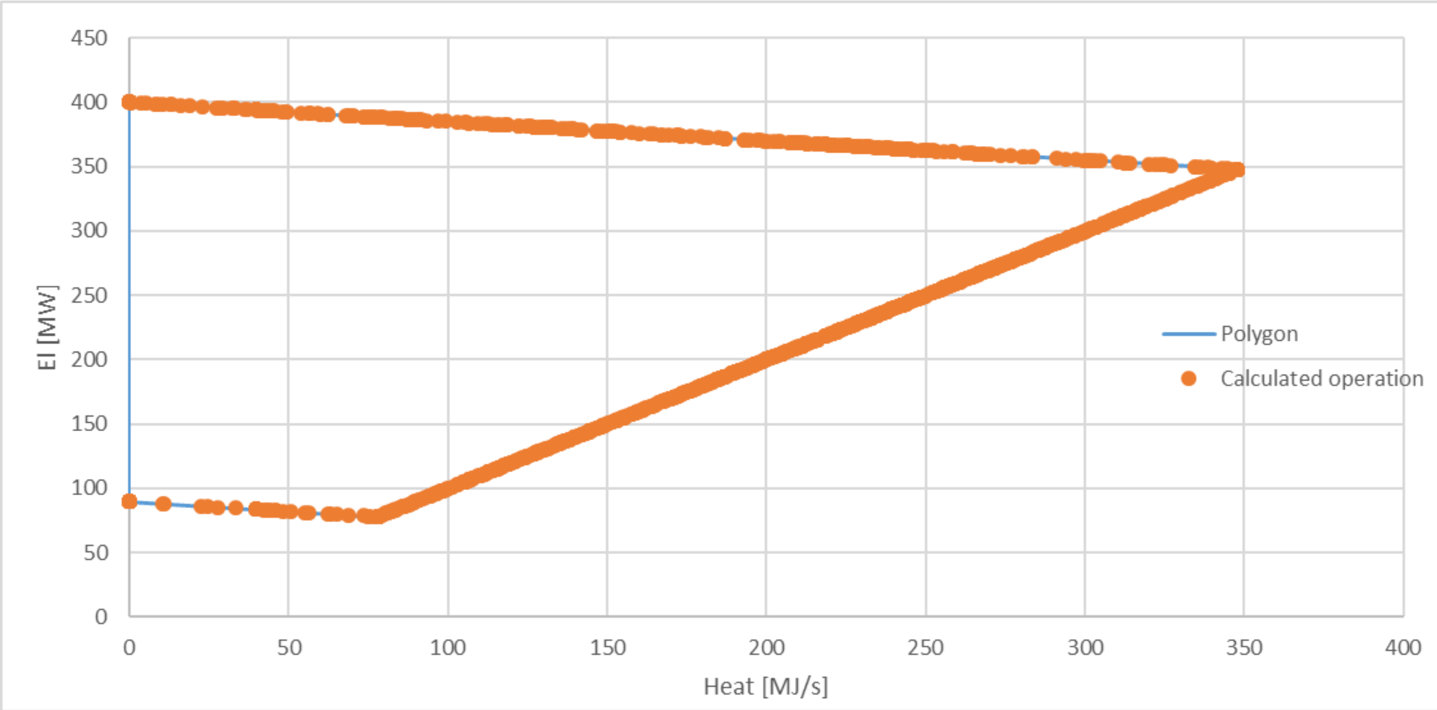


Figure 29: The operation of the CHP in each hour of the 2019, using the analytical UC method described in this section.

Further research might compare analytic and solver-based UC methods for operating such CHPs.

6.3.2 Serial coupled central and booster heat pumps

In the paper *Booster heat pumps and central heat pumps in district heating* [23][1] is shown another example of ECUs that as generalized input/output units can convert energy types to other energy types. The booster heat pump is an example of such an ECU. It converts the energy type “low temperature district heat” together with the energy type “electricity” to the energy type “hot water”. Heat source for the central heat pump is ambient temperature. Through functional expressions the load curve for the central heat pump will differ from hour to hour depending on ambient temperature as well as flow and return temperature in the district heating grid. Similarly, through functional expressions the load curve for the booster heat pumps will depend on hot water temperature to be delivered as well as flow and return temperature in the district heating grid. The functional expressions are given in [23].

[1] The PhD candidate’s contribution to this article was the model development and implementation in energyPRO. The remainder including application and analyses were done by the first author.

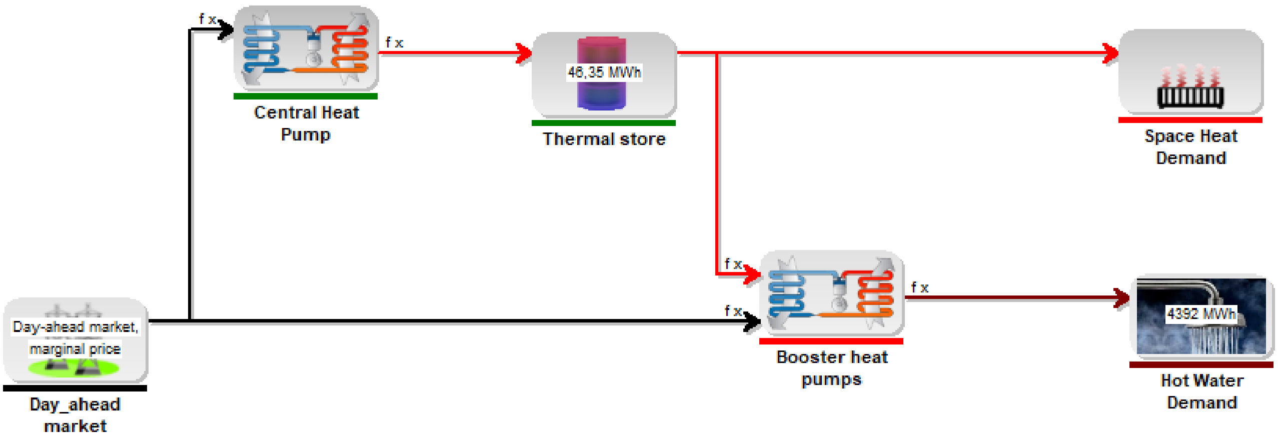


Figure 30: A diagram showing a central heat pump delivering low temperature district heating to cover space heat in each building, as well as being heat source for a booster heat pump producing hot water in each building.

The electricity consumed by the central heat pump is assumed to be purchased in the Day-ahead market, and the district heating is assumed to be able to be stored in a large thermal store. An example of the operation of the central heat pump and the use of the thermal store is shown for a week in Figure 31. The upper graphs show the hourly prices in the Day-ahead market. The next two graphs show the heat production and the electricity consumption of the central heat pump. The bottom graph shows the content in the thermal store. It is seen that e.g. June 27th the spot prices are high; thus, the central heat pump is not operated.

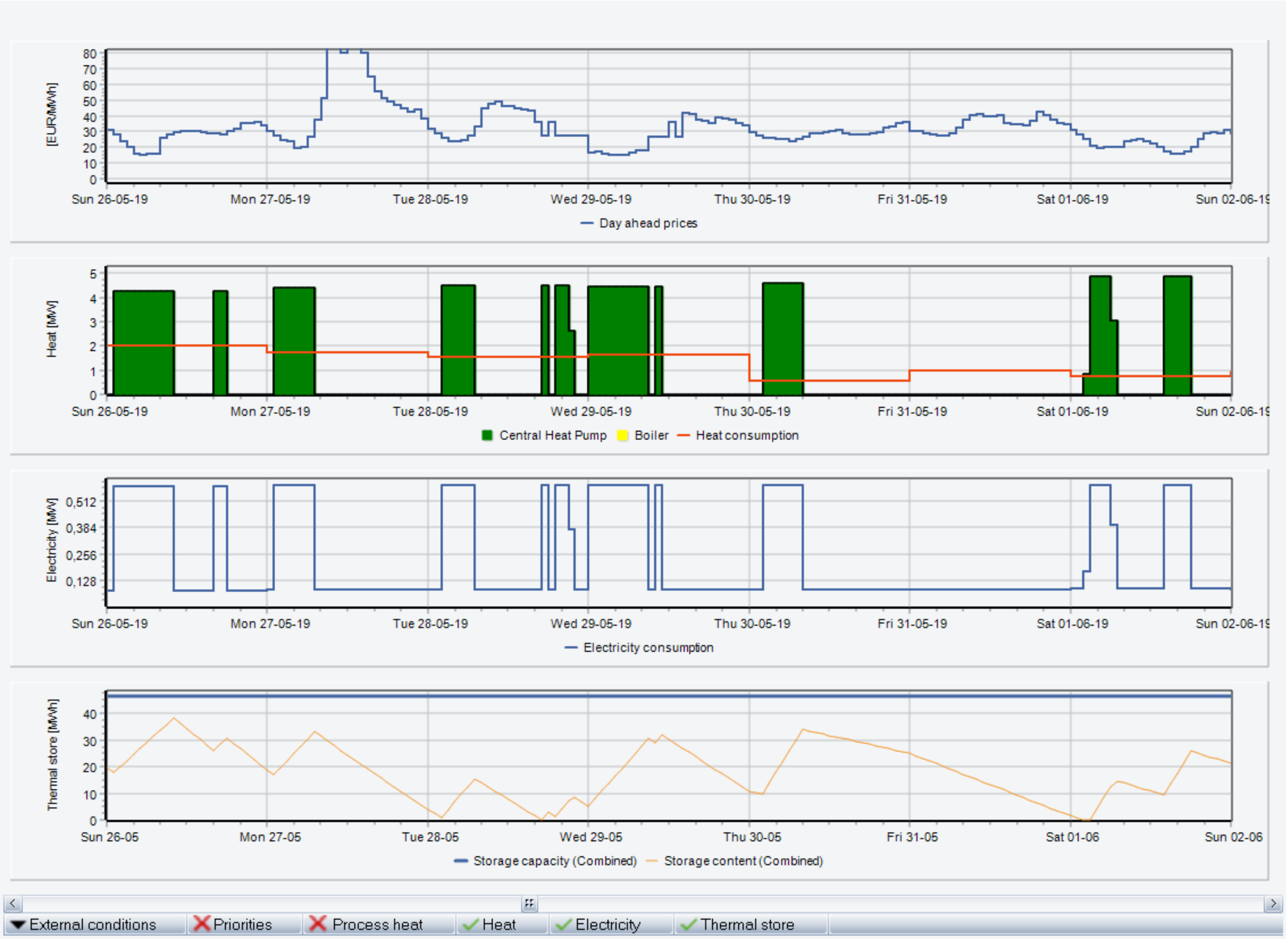


Figure 31: An example in a week of the operation of the central heat pump of the DE plant shown in Figure 30.[2]

[2] The PhD candidate's contribution to this article was the model development and implementation in energyPRO. The remainder including application and analyses were done by the first author

6.3.3 Absorption chiller in a trigeneration plant

The operation of an absorption chiller is another challenging example of UCs at DE plants, because the energy input to one production unit (heat is needed for the absorption chiller) is to be produced by other production unit. Apparently, this UC is not easily made with an analytic UC method, because the needed priority numbers again become multi-dimensional. An example of such a DE plant illustrated in Figure 32. The absorption chiller consumes the energy type heat and produces the energy type cooling to cover a cooling demand. But covering the cooling demand is in competition with any of the electric chillers. Either (or both) an analytical method or a solver method may be used to determine the optimal UC of the absorption chiller and the electric chiller, as well as the UC of the two CHPs and the boiler, taking into account that the produced heat can be stored in a thermal store before covering both the heat demand and the heat consumed by the absorption chiller. Furthermore, it has to be taken into account that electricity produced by the CHPs may be sold in a Day-ahead market at hourly prices and that the consumption of the electric chiller has to be purchased in the Day-ahead market.

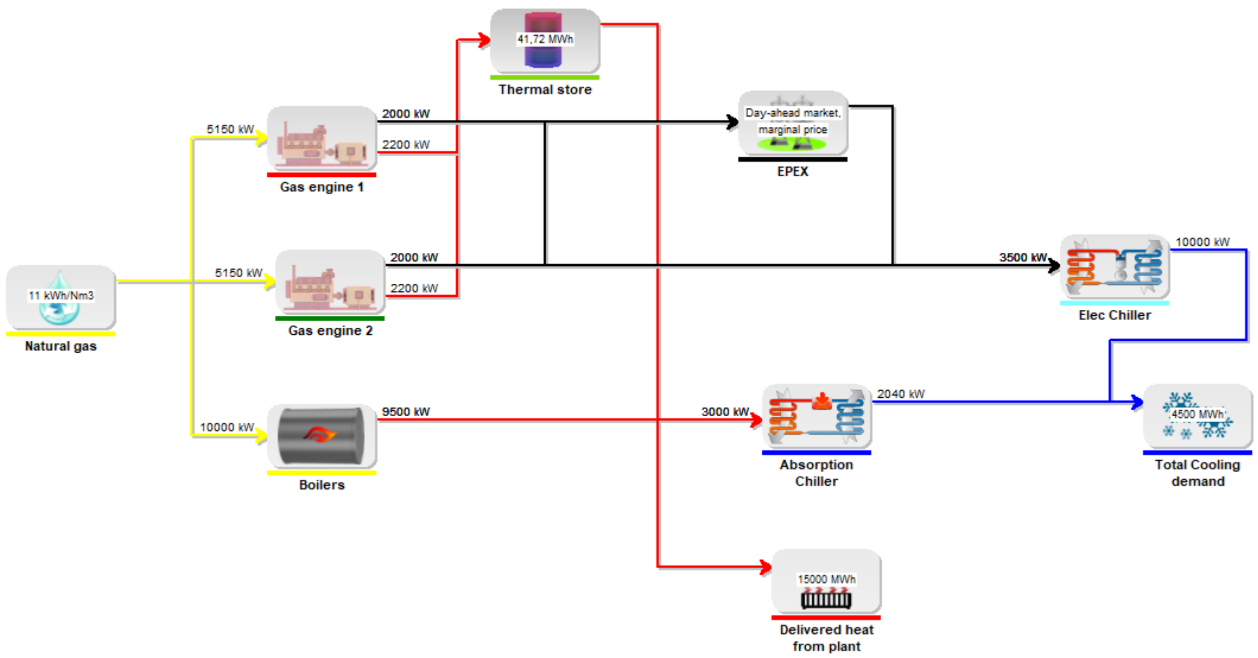


Figure 32: Absorption chiller in a trigeneration plant

Below is described an idea making use of an analytic UC methods, allowing the dispatch of the production units according to priority numbers.

The first step is to attribute priority numbers to the CHPs and boilers, which could be the hourly NHPCs. An example of these NHPCs are shown in Figure 33. It is seen that at a spot price of around 38 EUR/MWh$_e$ the NHPC of the CHPs and the boiler is the same around 24 EUR/MWh$_{heat.}$

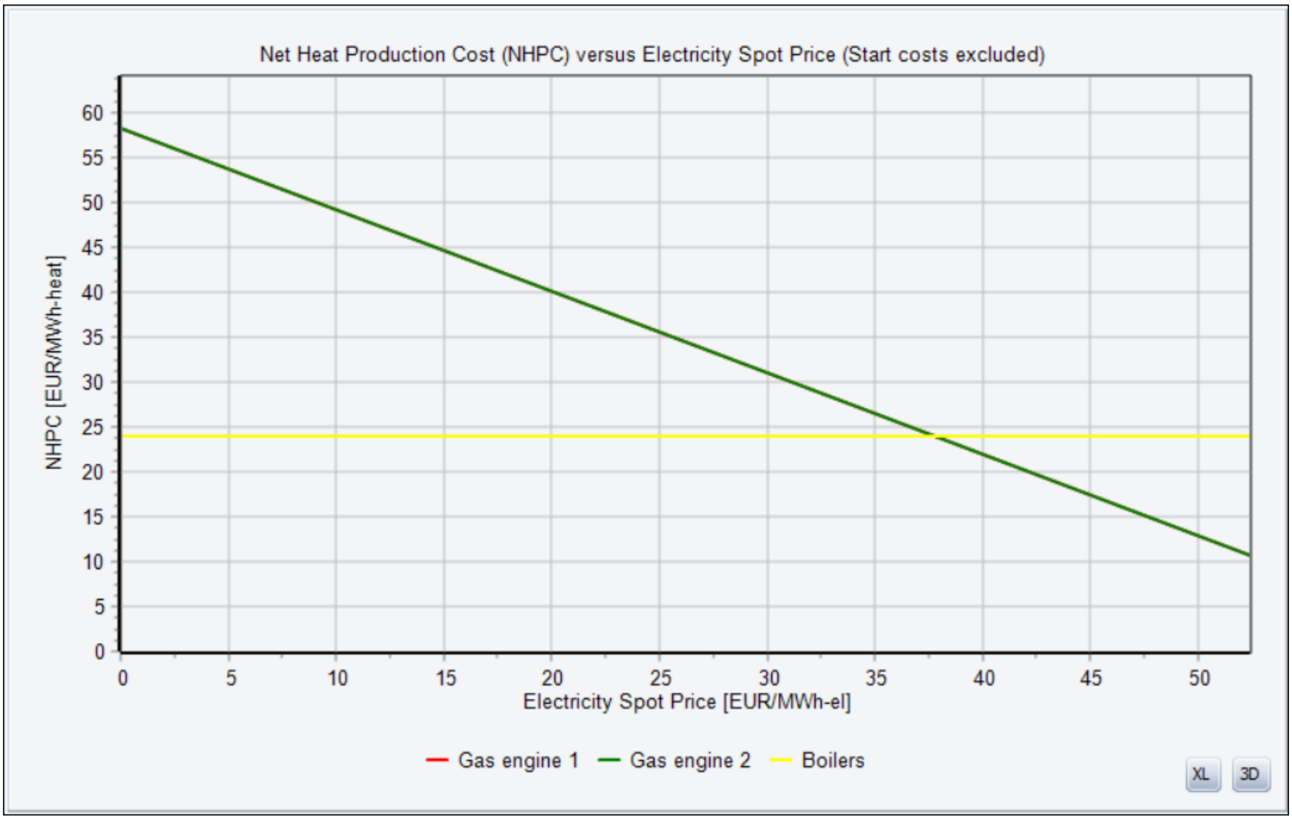


Figure 33: NHPCs of the heat producing units of the DE plant shown in Figure 32.

The next step is to attribute priority numbers to the absorption chiller and the electric chiller, which could be the hourly Net Cooling Production Cost (NCPC). This is straightforward to do for the electric chiller and its NCPC is shown in Figure 34. However, when coming to the absorption chiller its ability to produce cheap cooling depends on if it receives cheap heat from the heat producing units, thus it becomes a two-dimensional problem, where there has to be an absorption chiller NCPC-graph for each heat producing unit. It is seen in the graph that the absorption chiller produces cheaper cooling than the electric chiller, if the spot prices are above 38 EUR/MWh$_e$ and if the heat is coming from the CHPs. It is to be kept in mind that the heat consumed in a certain time step of the absorption chiller is not necessarily produced in that time step but may be produced earlier and stored in the thermal store.

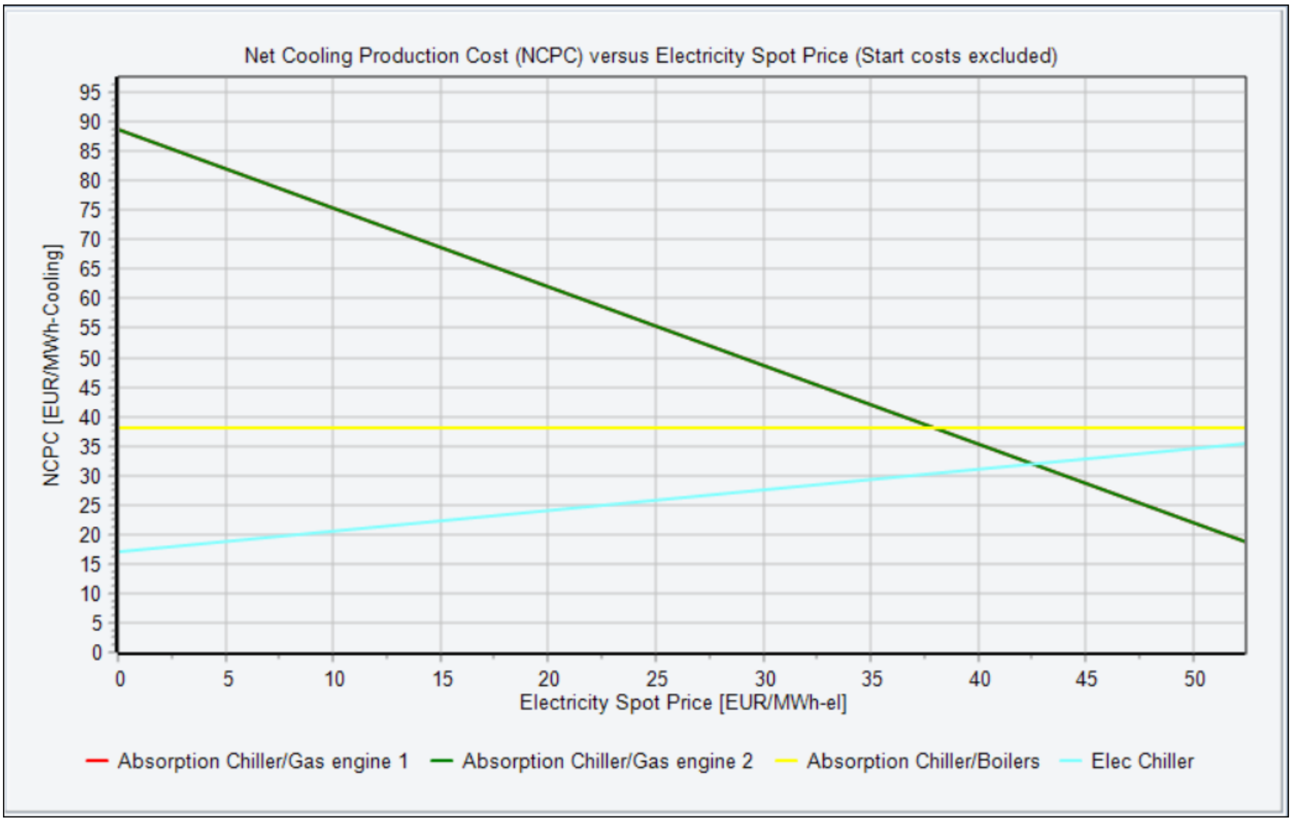


Figure 34: NCPCs of the cooling producing units of the DE plant shown in Figure 32.

The optimal UC of the DE plant shown in Figure 32, found by an analytical method and based on these precalculated NHCPs and NCPCs, could be made in the following way. The first step is to cover the heat demand using NHPCs as priority numbers. Nest step could be to cover the cooling demand by noticing in each time step the NCPC of the electrical chiller. This creates the highest NCPC allowed in that time step, because the electric chiller is able to produce cooling at that price. This NCPC in that time step then is the highest allowed NCPC, which then for the absorption chiller can be converted to the highest allowed price for heat in that time step. The analytical method is then to make the absorption chiller ask for heat from the three heat producing units if they in some time step before are able to produce heat at a lower price than this highest allowed price for heat, eventually may the heat be stored in the thermal store before being used by the absorption chiller in that time step. This analytical method gives the UC shown in Figure 35. The upper graphs show the hourly prices in the Day-ahead market. The next two graphs show the heat and the electricity productions and consumptions. The bottom graph shows the content in the thermal store. It is seen that e.g. 15th of July the absorption chiller is operating introducing a large heat consumption when operating.

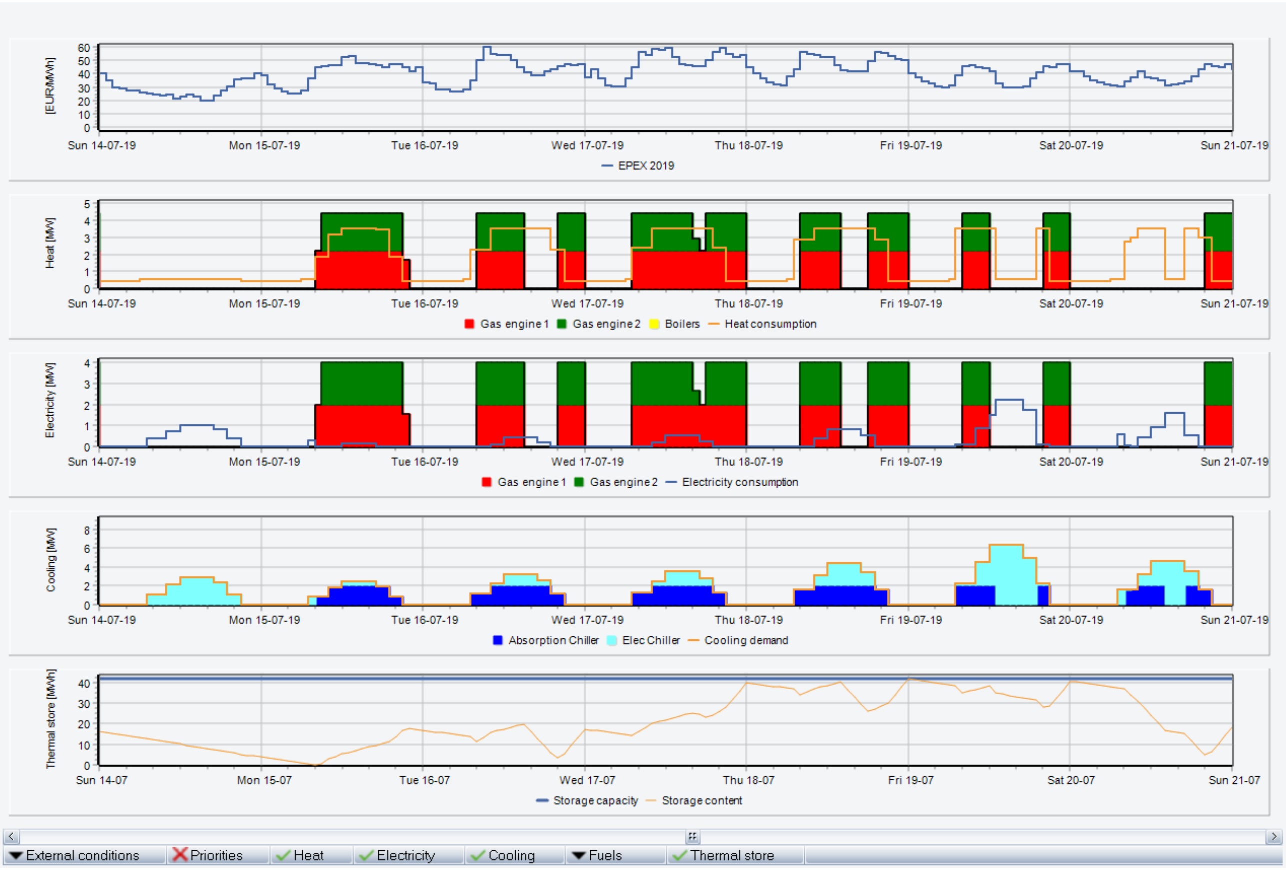


Figure 35: An example of UC at the DE plant shown in Figure 32.

6.3.4 Batteries in private wire operation

One important and challenging next steps in the research of the UCs for DE plants, making use of and combining the best of analytic and solver-based UC methods, is private wire operation, where e.g. a large electrical grid tariff is avoided when electricity demand is covered by own production units.

Analytic UC methods could still be involved in meeting this UC challenge. This is illustrated in Figure 36 showing a diagram for a battery in a private wire operation. The battery is modelled as a fuel (chemical energy), where a charger can produce this fuel consuming electricity and a discharger can consume this fuel and produce electricity. Because there is a PV in the private wire, the priority of the charger depends on if it consumes electricity from the PV or it consumes electricity from import (paying taxes and grid tariff of this import). This is simply modelled by splitting the charger into two units, that together must consume less than the capacity of the charger. The *Charge from production*-unit (the auto production at site) is only allowed to charge with a power equal to the instantaneous PV production minus the electricity demand. In the same way the discharger is split into two units.

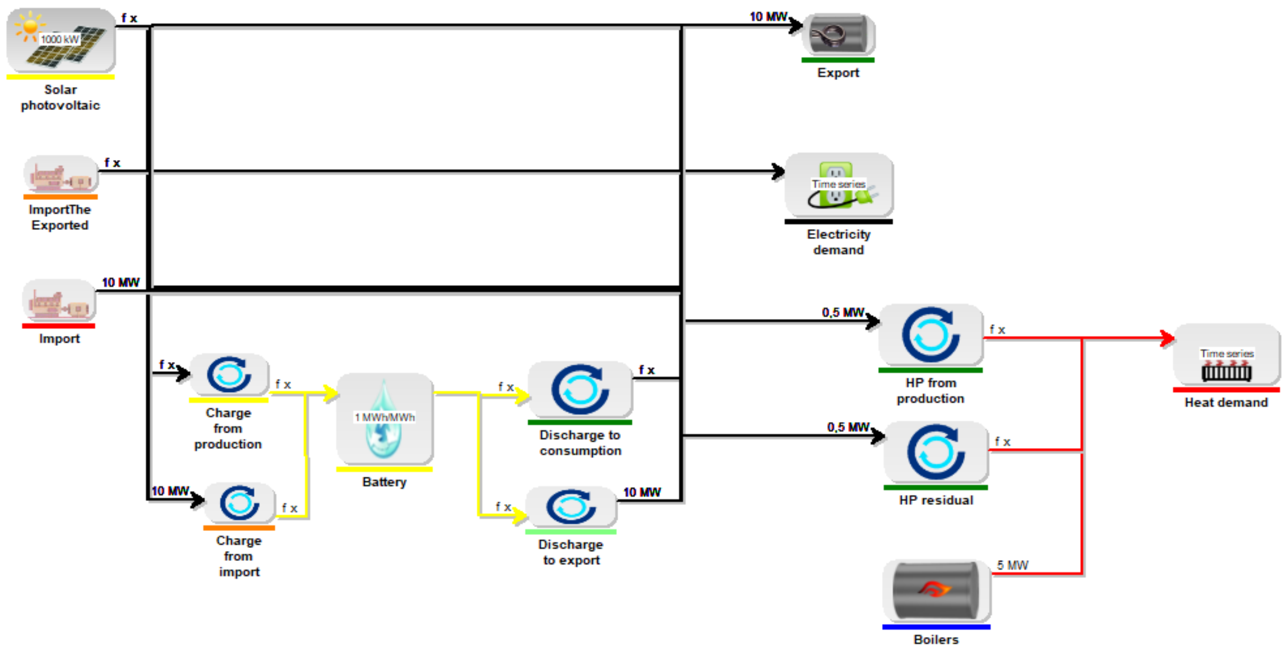


Figure 36: Batteries in private wire operation

6.4 More research in the value of a generalized tool is needed

As described in Section 1.7, the main research question of this thesis concerns the development of generalized tools, which is able to analyse very different alternatives for DE plants providing heating and cooling.

It is outside the scope of this PhD to study and quantify the value of developing these tools. This PhD study is restricted to the company perspective of DE plant, but it is assumed that awareness of radical technological different alternatives, made quantified available in one tool, are valuable for amongst other managers of DE plants and their consultants. A further research into this assumed value could draw parallels to the societal Choice Awareness theory [122]. In general, the Choice Awareness theory states that existing organizations and institutions, according to their own perceptions of the world and to maintain their existing positions, will influence public opinion and the solution choices available. Further, the theory states that society as a whole can benefit from promoting awareness of technical, and potentially more feasible, alternatives to those suggested by existing organisations.

7. Conclusion

Flexible DE plants have an important role in the transition to a renewable energy system, as they may become major actors in integrating wind and solar power, when amongst others equipped with CHPs and heat pumps producing both heating and cooling.
This integration of the DE plants with the rest of the energy system will often be based on biddings in electricity and fuel markets and affected by availability of fluctuating energy sources and large energy stores, as well as being based on complex subsidy schemes and energy taxes. This calls for new generalized tools which are able to analyse very different alternatives for DE plants providing heating and cooling.

The research made in this PhD study concerns the development of the next generation generalized energy system simulation tools for designing and operating DE plants.

The research has been delimited to tools needed for the following tasks in DE plants:

- Investment analysis for comparing very different alternatives for complex future DE plants operating in complex energy markets subject to complex support schemes and energy taxes.
- Daily or short-term planning of operation, also when this operation is determined from biddings in the electricity and fuel markets and affected by availability of fluctuating energy sources, large energy stores and restricted capacities in the heating, cooling and electrical grids.

The main research question is:
Is it possible to develop a generalized tool which is able to analyse and compare sufficiently detailed very different alternatives for DE plants providing heating and cooling?

For such a tool to be appropriate for practitioners, it has to offer an acceptable time setting up models, an acceptable calculation time and it should use a calculation method understandable by the managers of the DE plants.

To make this research question operational as well as to delimit it, three sub questions are formulated:

Sub question 1: *How can the optimization of market based daily operation of DE plants with large TES be solved?*

Sub question 2: *How can a coordinated investment in production and storage capacity at DE plants be analysed?*

Sub question 3: *How can the effect of support schemes promoting necessary flexibility at DE plants be analysed?*

For establishing the research's novelty and scope a literature review has been presented, showing that there is major societal benefits of DE, flexibility of DE plants is needed, CHP at DE plants when developing renewable energy meets changing roles, daily operation of DE plants with large energy stores needs optimization, support schemes promoting necessary flexibility at DE plants is needed and it is made probable that large investments in production capacity at DE plants has to be made, justifying the large effort to be made to develop next generation generalized energy system simulation tools for designing and operating DE plants.

To answer the main research question and the three sub questions, complex generic DE plants have been designed. Still, the reproducible research paradigm has been pursued in this thesis, so that even if it is complex plants considered, the description of these and the methods presented are sought to be so detailed described, that it allows readers reproducing with minimal effort the results obtained.

To give an answer to Sub question 1, two significantly different UC methods is presented, which show that the optimization of market-based daily operation of these generic DE plants with large TES are able to be solved in a sufficient detail and fast. The one UC method is based on Mixed Integer Linear Programming. The other UC method presented is an advanced analytic method based on priority numbers detailed for each production unit in each time step. The novelty in the answer to Sub question 1 is thus that it brings analytic UC methods back as potential attractive methods to be used at DE plants for daily operation planning, yearly budgeting and long-term investment analysis.

Investments in large production capacity compared to the instantaneous heat demand at a DE plant needs new methods to be analysed, simply because the feasibility of an investment will be closely dependent on a simultaneous investment in a large TES. To give an answer to Sub question 2, a method for analysing coordinated investments in production and storage capacity is presented. It is demonstrated that the presented method returns reliable results, when dealing with the complex generic DE plants being suggested and when using the presented UC methods.

Often support schemes are required to fulfil the role DE plants have to play when developing renewable energy. To give an answer to Sub question 3, a method for comparing support schemes promoting CHPs, HPs and TES at DE plants has been presented. The methods are used to compare two support schemes, one of a Feed-in premium type and one of a Feed-in tariff type. The effect of these two support schemes are tested on the complex generic DE plants, while using the method for analysing coordinated investments in production and storage capacity. It is shown that the societal cost for providing a certain production capacity, measured as the support in the planning period, is around three time larger when using the Feed-in premium type as when using the Feed-in tariff type.

However, in the discussion in Section 6, DE plants are presented that differ significantly from the generic DE plants studied in this PhD study, amongst others CHP operated in both condensing mode and extraction mode, serial coupled central and booster heat pumps, absorption chillers in trigeneration plants and batteries in private wire operation. Furthermore, in the discussion is elaborated on the challenge of optimizing DE plants participating across more of the electricity markets, by showing examples of real plant operations. These specific DE plants and examples from real plant operations presented should be further researched in the future for the pursuit of developing next generation generalized energy system simulation tools for designing and operating DE plants.

8. References

[1] UNEP. District Energy in Cities, Unlocking the Potential of Energy Efficiency and Renewable Energy. 2015.

[2] World Urbanization Prospects: The 2018 Revision. n.d.

[3] District energy: a tried-and-tested answer to modern urban energy problems :: Our Planet n.d. http://www.unep.org/ourplanet/october-2016/unep-work/district-energy-tried-and-tested-answer-modern-urban-energy-problems (accessed July 27, 2018).

[4] Panayiotou GP, Bianchi G, Georgiou G, Aresti L, Argyrou M, Agathokleous R, et al. Preliminary assessment of waste heat potential in major European industries. Energy Procedia, vol. 123, Elsevier; 2017, p. 335–45. doi:10.1016/j.egypro.2017.07.263.

[5] Winterscheid C, Dalenbäck J-O, Holler S. Integration of solar thermal systems in existing district heating systems. Energy 2017;137:579–85. doi:10.1016/j.energy.2017.04.159.

[6] Averfalk H, Ingvarsson P, Persson U, Gong M, Werner S. Large heat pumps in Swedish district heating systems. Renew Sustain Energy Rev 2017;79:1275–84. doi:10.1016/j.rser.2017.05.135.

[7] Østergaard PA, Lund H. A renewable energy system in Frederikshavn using low-temperature geothermal energy for district heating. Appl Energy 2011;88:479–87. doi:10.1016/j.apenergy.2010.03.018.

[8] Energy saving analysis of the cooling plant using lake water source base on the optimized control strategy with set points change. Appl Therm Eng 2017. doi:10.1016/J.APPLTHERMALENG.2017.10.152.

[9] 2050 Energy Strategy - European Commission n.d. https://ec.europa.eu/energy/en/topics/energy-strategy-and-energy-union/2050-energy-strategy (accessed September 28, 2018).

[10] European Commission. HORIZON 2020 -Work Programme 2016 -2017 "Secure, Clean and Efficient Energy." 2016.

[11] Connolly D, Lund H, Mathiesen BV, Werner S, Möller B, Persson U, et al. Heat Roadmap Europe: Combining district heating with heat savings to decarbonise the EU energy system. Energy Policy 2014;65:475–89. doi:10.1016/j.enpol.2013.10.035.

[12] Möller B, Nielsen S. High resolution heat atlases for demand and supply mapping. Int J Sustain Energy Plan Manag 2014;1:41–58. doi:10.5278/IJSEPM.2014.1.4.

[13] Sperling K, Möller B. End-use energy savings and district heating expansion in a local renewable energy system – A short-term perspective. Appl Energy 2012;92:831–42. doi:10.1016/j.apenergy.2011.08.040.

[14] Østergaard PA. Heat savings in energy systems with substantial distributed generation. J Sustain Energy 2003.

[15] Thellufsen JZ, Lund H. Energy saving synergies in national energy systems. Energy Convers Manag 2015;103:259–65. doi:10.1016/J.ENCONMAN.2015.06.052.

[16] Lund H, Thellufsen JZ, Aggerholm S, Wittchen KB, Nielsen S, Mathiesen BV, et al. Heat Saving Strategies in Sustainable Smart Energy Systems. Int J Sustain Energy Plan Manag 2014;4:3–16. doi:10.5278/IJSEPM.2014.4.2.

[17] Mosgaard M, Maneschi D. The energy renovation journey. Int J Innov Sustain Dev

2016;10:177. doi:10.1504/IJISD.2016.075548.
[18] Mathiesen BV, Lund H. Comparative analyses of seven technologies to facilitate the integration of fluctuating renewable energy sources. IET Renew Power Gener 2009;3:190. doi:10.1049/iet-rpg:20080049.
[19] Connolly D, Mathiesen BV. A technical and economic analysis of one potential pathway to a 100% renewable energy system. Int J Sustain Energy Plan Manag 2014;1:7–28. doi:10.5278/IJSEPM.2014.1.2.
[20] Østergaard PA. Wind power integration in Aalborg Municipality using compression heat pumps and geothermal absorption heat pumps. Energy 2013;49:502–8. doi:10.1016/j.energy.2012.11.030.
[21] Østergaard PA. Reviewing optimisation criteria for energy systems analyses of renewable energy integration. Energy 2009;34:1236–45. doi:10.1016/J.ENERGY.2009.05.004.
[22] Brito M, Sousa T. Development of a “Current Energy Mix Scenario” and a “Electricity as Main Energy Source Scenario” for electricity demand up to 2100. Int J Sustain Energy Plan Manag 2014;2:63–80. doi:10.5278/IJSEPM.2014.2.6.
[23] Østergaard PA, Andersen AN. Booster heat pumps and central heat pumps in district heating. Appl Energy 2016. doi:10.1016/j.apenergy.2016.02.144.
[24] Köfinger M, Basciotti D, Schmidt RR, Meissner E, Doczekal C, Giovannini A. Low temperature district heating in Austria: Energetic, ecologic and economic comparison of four case studies. Energy 2016;110:95–104. doi:10.1016/J.ENERGY.2015.12.103.
[25] Zvingilaite E, Ommen TS, Elmegaard B, Franck ML. Low Temperature District Heating Consumer Unit with Micro Heat Pump for Domestic Hot Water Preparation 2012:136–43.
[26] Ommen T, Markussen WB, Elmegaard B. Lowering district heating temperatures – Impact to system performance in current and future Danish energy scenarios. Energy 2016;94:273–91. doi:10.1016/J.ENERGY.2015.10.063.
[27] Elmegaard B, Ommen TS, Markussen M, Iversen J. Integration of space heating and hot water supply in low temperature district heating. Energy Build 2016;124:255–64. doi:10.1016/J.ENBUILD.2015.09.003.
[28] Lund H, Werner S, Wiltshire R, Svendsen S, Thorsen JE, Hvelplund F, et al. 4th Generation District Heating (4GDH): Integrating smart thermal grids into future sustainable energy systems. Energy 2014;68:1–11. doi:10.1016/J.ENERGY.2014.02.089.
[29] Vindmølleforening D. Wind energy capacity 2016. http://www.dkvind.dk/html/nogletal/kapacitet.html (accessed November 13, 2016).
[30] Danish Energy Agency. The electrical infrastructure in Denmark n.d. http://www.ens.dk/info/tal-kort/energikort/download-faerdige-kort (accessed July 8, 2016).
[31] Persson U, Möller B, Werner S. Heat Roadmap Europe: Identifying strategic heat synergy regions. Energy Policy 2014;74:663–81. doi:10.1016/j.enpol.2014.07.015.
[32] Danish Energy Agency. Energy Statistic 2014 [Energistatistik 2014]. 2015.
[33] Danish Parliament. BEK nr 760 af 24/06/2013. 2013.
[34] EMD International. energyPRO n.d. http://www.emd.dk/energypro/ (accessed July 17, 2016).
[35] Energinet.dk. Download of market data 2016. http://energinet.dk/EN/El/Engrosmarked/Udtraek-af-markedsdata/Sider/default.aspx (accessed November 13, 2016).

[36] Energinet.dk. Energy concepts 2030 [Energikoncept 2030 - Baggrundsrapport]. 2015.
[37] Energinet.dk. Analysis assumptions [Energinet.dk's analyseforudsætninger 2016]. 2016.
[38] Andersen AN, Lund H. New CHP partnerships offering balancing of fluctuating renewable electricity productions. J Clean Prod 2007;15:288–93.
[39] Andersen AN, Østergaard PA. A method for assessing support schemes promoting flexibility at district energy plants. Appl Energy 2018;225:448–59. doi:10.1016/J.APENERGY.2018.05.053.
[40] Hvelplund F, Østergaard PA, Möller B, Mathiesen BV, Karnøe P, Andersen AN, et al. System and market integration of wind power in Denmark. Energy Strateg Rev 2013;1:143–56. doi:10.1016/j.esr.2012.12.003.
[41] Zheng QP, Wang J, Liu AL. Stochastic Optimization for Unit Commitment—A Review. IEEE Trans Power Syst 2015;30:1913–24. doi:10.1109/TPWRS.2014.2355204.
[42] Zheng H, Jian J, Yang L, Quan R. A deterministic method for the unit commitment problem in power systems. Comput Oper Res 2016;66:241–7. doi:10.1016/J.COR.2015.01.012.
[43] Abujarad SY, Mustafa MW, Jamian JJ. Recent approaches of unit commitment in the presence of intermittent renewable energy resources: A review. Renew Sustain Energy Rev 2017;70:215–23. doi:10.1016/J.RSER.2016.11.246.
[44] Senjyu T, Kai Shimabukuro, Uezato K, Funabashi T. A fast technique for unit commitment problem by extended priority list. IEEE Trans Power Syst 2003;18:882–8. doi:10.1109/TPWRS.2003.811000.
[45] Ommen T, Markussen WB, Elmegaard B. Comparison of linear, mixed integer and non-linear programming methods in energy system dispatch modelling. Energy 2014;74:109–18. doi:10.1016/J.ENERGY.2014.04.023.
[46] Kia M, Setayesh Nazar M, Sepasian MS, Heidari A, Siano P. An efficient linear model for optimal day ahead scheduling of CHP units in active distribution networks considering load commitment programs. Energy 2017;139:798–817. doi:10.1016/J.ENERGY.2017.08.008.
[47] ACER n.d. https://www.acer.europa.eu/en/Pages/default.aspx (accessed May 11, 2018).
[48] MARRAZI E, YANG G, WEINREICH-JENSEN P. Allocation of synchronous condensers for restoration of system short-circuit power. J Mod Power Syst Clean Energy 2018;6:17–26. doi:10.1007/s40565-017-0346-4.
[49] Rooijers FJ, van Amerongen RAM. Static economic dispatch for co-generation systems. IEEE Trans Power Syst 1994;9:1392–8. doi:10.1109/59.336125.
[50] Wang H, Yin W, Abdollahi E, Lahdelma R, Jiao W. Modelling and optimization of CHP based district heating system with renewable energy production and energy storage. Appl Energy 2015;159:401–21. doi:10.1016/J.APENERGY.2015.09.020.
[51] Lahdelma R, Hakonen H. An efficient linear programming algorithm for combined heat and power production. Eur J Oper Res 2003;148:141–51. doi:10.1016/S0377-2217(02)00460-5.
[52] Thorin E, Brand H, Weber C. Long-term optimization of cogeneration systems in a competitive market environment. Appl Energy 2005;81:152–69. doi:10.1016/J.APENERGY.2004.04.012.
[53] Anand H, Narang N, Dhillon JS. Unit commitment considering dual-mode combined heat and power generating units using integrated optimization technique. Energy Convers Manag 2018;171:984–1001. doi:10.1016/J.ENCONMAN.2018.06.054.
[54] Basu M. Combined heat and power economic emission dispatch using nondominated sorting genetic algorithm-II. Int J Electr Power Energy Syst 2013;53:135–41.

doi:10.1016/J.IJEPES.2013.04.014.
[55] Takada K, Ikegami T. Long-term Planning Model for a CHP System Using Particle Swarm Optimization algorithm and Mixed Integer Linear Programming. 2018 Int. Conf. Smart Energy Syst. Technol., IEEE; 2018, p. 1–6. doi:10.1109/SEST.2018.8495672.
[56] Song YH, Chou CS, Stonham TJ. Combined heat and power economic dispatch by improved ant colony search algorithm. Electr Power Syst Res 1999;52:115–21. doi:10.1016/S0378-7796(99)00011-5.
[57] Gopalakrishnan H, Kosanovic D. Economic optimization of combined cycle district heating systems. Sustain Energy Technol Assessments 2014;7:91–100. doi:10.1016/J.SETA.2014.03.006.
[58] Abdolmohammadi HR, Kazemi A. A Benders decomposition approach for a combined heat and power economic dispatch. Energy Convers Manag 2013;71:21–31. doi:10.1016/J.ENCONMAN.2013.03.013.
[59] Rong A, Hakonen H, Lahdelma R. An efficient linear model and optimisation algorithm for multi-site combined heat and power production. Eur J Oper Res 2006;168:612–32. doi:10.1016/J.EJOR.2004.06.004.
[60] Sudhakaran M, Slochanal SMR. Integrating genetic algorithms and tabu search for combined heat and power economic dispatch. TENCON 2003. Conf. Converg. Technol. Asia-Pacific Reg., Allied Publishers Pvt. Ltd; n.d., p. 67–71. doi:10.1109/TENCON.2003.1273225.
[61] Basu M. Bee colony optimization for combined heat and power economic dispatch. Expert Syst Appl 2011;38:13527–31. doi:10.1016/J.ESWA.2011.03.067.
[62] Vasebi A, Fesanghary M, Bathaee SMT. Combined heat and power economic dispatch by harmony search algorithm. Int J Electr Power Energy Syst 2007;29:713–9. doi:10.1016/J.IJEPES.2007.06.006.
[63] Powell KM, Kim JS, Cole WJ, Kapoor K, Mojica JL, Hedengren JD, et al. Thermal energy storage to minimize cost and improve efficiency of a polygeneration district energy system in a real-time electricity market. Energy 2016;113:52–63. doi:10.1016/j.energy.2016.07.009.
[64] Pavičević M, Novosel T, Pukšec T, Duić N. Hourly optimization and sizing of district heating systems considering building refurbishment – Case study for the city of Zagreb. Energy 2017;137:1264–76. doi:10.1016/J.ENERGY.2017.06.105.
[65] Wang J, Zhou Z, Zhao J, Zheng J. Improving wind power integration by a novel short-term dispatch model based on free heat storage and exhaust heat recycling. Energy 2018;160:940–53. doi:10.1016/J.ENERGY.2018.07.018.
[66] Romanchenko D, Odenberger M, Göransson L, Johnsson F. Impact of electricity price fluctuations on the operation of district heating systems: A case study of district heating in Göteborg, Sweden. Appl Energy 2017;204:16–30. doi:10.1016/J.APENERGY.2017.06.092.
[67] Carpaneto E, Lazzeroni P, Repetto M. Optimal integration of solar energy in a district heating network. Renew Energy 2015;75:714–21. doi:10.1016/J.RENENE.2014.10.055.
[68] Bachmaier A, Narmsara S, Eggers J-B, Herkel S. Spatial Distribution of Thermal Energy Storage Systems in Urban Areas Connected to District Heating for Grid Balancing. Energy Procedia 2015;73:3–11. doi:10.1016/J.EGYPRO.2015.07.549.
[69] Bachmaier A, Narmsara S, Eggers J-B, Herkel S. Spatial distribution of thermal energy storage systems in urban areas connected to district heating for grid balancing—A techno-economical optimization based on a case study. J Energy Storage 2016;8:349–57. doi:10.1016/J.EST.2016.05.004.

[70] Support schemes - European Commission n.d. https://ec.europa.eu/energy/en/topics/renewable-energy/support-schemes (accessed July 25, 2017).
[71] European Commission. COMMUNICATION FROM THE COMMISSION Delivering the internal electricity market and making the most of public intervention 2013.
[72] European Commission. European Commission Guidance for the Design of Renewables Support Schemes. 2013.
[73] Dressler L. Support schemes for renewable electricity in the European Union: Producer strategies and competition. Energy Econ 2016;60:186–96. doi:10.1016/j.eneco.2016.09.003.
[74] ISI F. Financing Renewable Energy in the European Energy Market. 2011.
[75] Jiménez Navarro JP, Cejudo López JM, Connolly D. The effect of feed-in-tariff supporting schemes on the viability of a district heating and cooling production system. Energy 2017;134:438–48. doi:10.1016/j.energy.2017.05.174.
[76] Schallenberg-Rodriguez J, Haas R. Fixed feed-in tariff versus premium: A review of the current Spanish system. Renew Sustain Energy Rev 2012;16:293–305. doi:10.1016/J.RSER.2011.07.155.
[77] Haas R, Panzer C, Resch G, Ragwitz M, Reece G, Held A. A historical review of promotion strategies for electricity from renewable energy sources in EU countries. Renew Sustain Energy Rev 2011;15:1003–34. doi:10.1016/J.RSER.2010.11.015.
[78] Mezősi A, Szabó L, Szabó S. Cost-efficiency benchmarking of European renewable electricity support schemes. Renew Sustain Energy Rev 2018;98:217–26. doi:10.1016/J.RSER.2018.09.001.
[79] Communication from the Commission — Guidelines on State aid for environmental protection and energy 2014-202 n.d. https://eur-lex.europa.eu/legal-content/EN/TXT/?uri=CELEX%3A52014XC0628%2801%29 (accessed December 9, 2018).
[80] Gawel E, Purkus A. Promoting the market and system integration of renewable energies through premium schemes—A case study of the German market premium. Energy Policy 2013;61:599–609. doi:10.1016/J.ENPOL.2013.06.117.
[81] Østergaard PA. Modelling grid losses and the geographic distribution of electricity generation. Renew Energy 2005;30:977–87. doi:10.1016/j.renene.2004.09.007.
[82] Soltero VM, Chacartegui R, Ortiz C, Velázquez R. Evaluation of the potential of natural gas district heating cogeneration in Spain as a tool for decarbonisation of the economy. Energy 2016;115:1513–32. doi:10.1016/j.energy.2016.06.038.
[83] Fragaki A, Andersen AN, Toke D. Exploration of economical sizing of gas engine and thermal store for combined heat and power plants in the UK. Energy 2008;33:1659–70. doi:10.1016/j.energy.2008.05.011.
[84] Sovacool BK. Energy policymaking in Denmark, implications for global energy security and sustainability. Energy Policy 2013;61.
[85] Toke D, Fragaki A. Do liberalised electricity markets help or hinder CHP and district heating? The case of the UK. Energy Policy 2008;36:1448–56. doi:10.1016/j.enpol.2007.12.021.
[86] Lund H. Large-scale integration of wind power into different energy systems. Energy 2005;30:2402–12. doi:10.1016/j.energy.2004.11.001.
[87] Lund H, Münster E. Integrated energy systems and local energy markets. Energy Policy 2006;34:1152–60. doi:10.1016/j.enpol.2004.10.004.
[88] Taljan G, Verbič G, Pantoš M, Sakulin M, Fickert L. Optimal sizing of biomass-fired Organic

Rankine Cycle CHP system with heat storage. Renew Energy 2012;41:29–38. doi:10.1016/j.renene.2011.09.034.
[89] Gebremedhin A, Carlson A. Optimisation of merged district-heating systems—benefits of co-operation in the light of externality costs. Appl Energy 2002;73:223–35. doi:10.1016/S0306-2619(02)00116-2.
[90] Heinz B, Henkel J. Balancing wind energy and participating in electricity markets with a fuel cell population. Energy 2012;48:188–95. doi:10.1016/j.energy.2012.07.002.
[91] Dominković DF, Ćosić B, Bačelić Medić Z, Duić N. A hybrid optimization model of biomass trigeneration system combined with pit thermal energy storage. Energy Convers Manag 2015;104:90–9. doi:10.1016/j.enconman.2015.03.056.
[92] EnergyPLAN. EnergyPLAN n.d. http://www.energyplan.eu/ (accessed November 2, 2016).
[93] Schroeder ST, Costa A, Obé E. Support schemes and ownership structures – the policy context for fuel cell based micro-combined heat and power. J Power Sources 2011;196:9051–7. doi:10.1016/j.jpowsour.2011.01.024.
[94] Hernández JC, Vidal PG, Almonacid G. Photovoltaic in grid-connected buildings, sizing and economic analysis. Renew Energy 1998;15:562–5. doi:10.1016/S0960-1481(98)00225-0.
[95] PwC Energiewende Outlook: Heating sector. n.d.
[96] District Energy in Germany | Euroheat & Power n.d. https://www.euroheat.org/knowledge-centre/district-energy-germany/ (accessed September 18, 2018).
[97] BMWi - Federal Ministry for Economic Affairs and Energy - Ready for the next phase of the energy transition n.d. https://www.bmwi.de/Redaktion/EN/Dossier/energy-transition.html (accessed September 18, 2018).
[98] Andersen AN, Østergaard PA. Support schemes for the radically changing role of District Energy CHPs through the transition to a renewable energy system. Second Rev Round Energy n.d.
[99] International Energy Agency n.d. https://www.iea.org/ (accessed September 22, 2018).
[100] Flyvbjerg B. Five Misunderstandings About Case-Study Research. Qual Inq 2006;12:219–45. doi:10.1177/1077800405284363.
[101] EMD International A/S References - EMD International A/S n.d. https://www.emd.dk/energypro/references/ (accessed July 24, 2017).
[102] Sorknæs P, Lund H, Andersen AN. Future power market and sustainable energy solutions – The treatment of uncertainties in the daily operation of combined heat and power plants. Appl Energy 2015;144:129–38. doi:10.1016/j.apenergy.2015.02.041.
[103] Østergaard PA, Andersen AN. Economic feasibility of booster heat pumps in heat pump-based district heating systems. Appl Energy 2018;Pending.
[104] Fragaki A, Andersen AN. Conditions for aggregation of CHP plants in the UK electricity market and exploration of plant size. Appl Energy 2011;88:3930–40. doi:10.1016/j.apenergy.2011.04.004.
[105] Fragaki A, Andersen AN, Toke D. Exploration of economical sizing of gas engine and thermal store for combined heat and power plants in the UK. Energy 2008;33:1659–70. doi:10.1016/j.energy.2008.05.011.
[106] Streckienė G, Martinaitis V, Andersen AN, Katz J. Feasibility of CHP-plants with thermal stores in the German spot market. Appl Energy 2009;86:2308–16. doi:10.1016/j.apenergy.2009.03.023.

[107] Østergaard PA. Comparing electricity, heat and biogas storages' impacts on renewable energy integration. Energy 2012;37:255–62. doi:10.1016/j.energy.2011.11.039.
[108] Gurobi Optimizer n.d. https://www.gurobi.com/products/product-overview (accessed March 23, 2019).
[109] Andersen AN, Østergaard PA. Analytic versus solver-based calculated daily operations of district energy plants. Energy 2019;175:333–44.
[110] GAMS - Cutting Edge Modeling n.d. https://www.gams.com/ (accessed December 23, 2018).
[111] Andres Ramos' Home Page n.d. https://www.iit.comillas.edu/aramos/ (accessed December 22, 2018).
[112] Danish Energy Agency. Catalogue of technologies n.d. https://ens.dk/service/fremskrivninger-analyser-modeller/teknologikataloger (accessed October 16, 2016).
[113] Gentile C, Morales-España G, Ramos A. A tight MIP formulation of the unit commitment problem with start-up and shut-down constraints. EURO J Comput Optim 2017;5:177–201. doi:10.1007/s13675-016-0066-y.
[114] Sameti M, Haghighat F. Optimization approaches in district heating and cooling thermal network. Energy Build 2017;140:121–30. doi:10.1016/J.ENBUILD.2017.01.062.
[115] Allegrini J, Orehounig K, Mavromatidis G, Ruesch F, Dorer V, Evins R. A review of modelling approaches and tools for the simulation of district-scale energy systems. Renew Sustain Energy Rev 2015;52:1391–404. doi:10.1016/j.rser.2015.07.123.
[116] Olsthoorn D, Haghighat F, Mirzaei PA. Integration of storage and renewable energy into district heating systems: A review of modelling and optimization. Sol Energy 2016;136:49–64. doi:10.1016/J.SOLENER.2016.06.054.
[117] Lyden A, Pepper R, Tuohy PG. A modelling tool selection process for planning of community scale energy systems including storage and demand side management. Sustain Cities Soc 2018. doi:10.1016/J.SCS.2018.02.003.
[118] Villa-Arrieta M, Sumper A. A model for an economic evaluation of energy systems using TRNSYS. Appl Energy 2018;215:765–77. doi:10.1016/J.APENERGY.2018.02.045.
[119] EMD International A/S Online Presentations - EMD International A/S n.d. https://www.emd.dk/energy-system-consultancy/online-presentations/ (accessed July 26, 2017).
[120] Frontpage | Energinet n.d. https://en.energinet.dk/ (accessed December 29, 2018).
[121] Ringkøbing Fjernvarmeværk n.d. http://www.rfv.dk/ (accessed September 14, 2018).
[122] Lund HH. Renewable energy systems : a smart energy systems approach to the choice and modeling of 100% renewable solutions. n.d.

ISSN (online): 2446-1628
ISBN (online): 978-87-7210-423-2

AALBORG UNIVERSITY PRESS